STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.
_______________________________________/

Case No. U-20162

Volume No. 3

CROSS-EXAMINATION

Proceedings held in the above-entitled matter before Sally L. Wallace, J.D., Administrative Law Judge with MAHS, at the Michigan Public Service Commission, 7109 West Saginaw Highway, Lake Michigan Room, Lansing, Michigan, on Wednesday, December 12, 2018, at 9:28 a.m.

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REPORTED BY: Marie T. Schroeder, CSR-2183
Lori Anne Penn, CSR-1315

I N D E X

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Lansing, Michigan
Wednesday, December 12, 2018
At 9:28 a.m.

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(Hearing resumes following adjournment of Thursday, November 1, 2018.)

JUDGE WALLACE: All right. Good morning everybody. We are on the record now, continuation in Case No. U-20162, In the matter of the application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.

I'm Sally Wallace, and I'm the administrative law judge assigned to this matter.

Let's see. For the record, may I have appearance of counsel, beginning with the Company, please.

MS. HAYDEN: Good morning, your Honor. Andrea Hayden and Jon Christinidis on behalf of DTE Electric Company.

JUDGE WALLACE: Thank you. Good morning. Commission Staff.

MR. SINGH: Good morning, your Honor. Amit Singh and Dan Sonneveldt on behalf of Michigan

Public Service Commission Staff.

JUDGE WALLACE: Thank you. Attorney General.

MR. KING: Good morning, your Honor. Joel King here on behalf of Attorney General Bill Schuette.

JUDGE WALLACE: Thank you. Good morning. ABATE.

MR. BRANDENBURG: Good morning, your Honor. Bryan Brandenburg appearing on behalf of ABATE.

JUDGE WALLACE: Good morning. ChargePoint.

MR. LUNDGREN: Good morning, your Honor. Tim Lundgren appearing on behalf of ChargePoint.

JUDGE WALLACE: O.K. Environmental Law & Policy Center, Ecology Center, Solar Energy Industries Association and Vote Solar.

MS. KEARNEY: Good morning, your Honor. Margrethe Kearney from ELPC on behalf of ELPC, Vote Solar, SEIA, and The Ecology Center; and I'd also at this time like to enter the appearance of Jean-Luc Kreitner on behalf of those parties with ELPC.

JUDGE WALLACE: Energy Michigan.

MR. LUNDGREN: Good morning, your Honor. Tim Lundgren appearing on behalf of Energy Michigan this

morning.

JUDGE WALLACE: Thank you. Good morning. Great Lakes Renewable Energy Association and Residential Customer Group.

MR. KESKEY: Good morning, your Honor. Don Keskey and Brian Coyer representing the Great Lakes Renewable Energy Association and also the Residential Customer Group.

JUDGE WALLACE: Good morning. Kroger Company.

MR. BOEHM: Good morning, your Honor. Kurt Boehm appearing on behalf of The Kroger Company.

JUDGE WALLACE: Good morning. O.K. Michigan Cable Telecommunications Association? (No response.)

Michigan Energy Innovation Business Council, Institute for Energy Innovation.

MR. LUNDGREN: Good morning, your Honor. Tim Lundgren appearing on behalf of Michigan Energy Innovation Business Council and Institute for Energy Innovation.

JUDGE WALLACE: Good morning again. Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club.

MR. BZDOK: Good morning, your Honor.

Christopher Bzdok on behalf of Michigan Environmental Council, the Natural Resources Defense Council, and Sierra Club. Also entering an appearance, the following appearances for Sierra Club: Shannon Fisk, Chinyere Osuala, and David Bender of Earthjustice.

JUDGE WALLACE: Thank you. Sierra Club is not -- are they appearing on -- it's on my list. The appearance for Sierra Club has been entered, correct?

MR. BZDOK: Yes.

JUDGE WALLACE: O.K. Good. Soulardarity.

MR. BZDOK: Yes, your Honor. Christopher Bzdok appearing as local counsel for Soulardarity, and later in this proceeding will be appearing from the University of Chicago and Abrams Environmental Law Clinic Mark Templeton and Robert Weinstock.

JUDGE WALLACE: Thank you. Utility Workers Local 223. (No response.)

Wal-Mart. (No response.)

All right. Is that everybody? I didn't miss anyone, did I? (No response.)

All right. Thank you, all. Next, is there anyone here wishing to make a statement pursuant to Rule 413? (No response.)

So no one. All right. Prior to going on

the record this morning we came up with a -- well, before we get to that, is there anything else that we need to address before we begin cross-examination? (No response.)

I need to remind everybody you need to speak loudly. Unfortunately, there's no speaker that goes that direction, so please keep your voices up.

All right. Ms. Hayden, why don't you go ahead with your first witness. Mr. Stanczak?

MS. HAYDEN: That's correct. Thank you, your Honor. The Company calls as its first witness Don Stanczak.

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D O N M. S T A N C Z A K

was called as a witness on behalf of DTE Electric Company and, having been duly sworn to testify the truth, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. HAYDEN:

Q Good morning.
A Good morning.
Q Could you please state your name and business address for the record?
A Don Stanczak, One Energy Plaza, Detroit, Michigan 48226.
Q Mr. Stanczak, did you file with the Commission a document

titled the Qualifications and Direct Testimony of Don Stanczak, consisting of a cover sheet and 33 pages of questions and answers?
A Yes.
Q Do you have any changes you wish to make to your testimony?
A Yes, I do. On page 28, line 25, strike out "Mr. Kenneth D. Johnston, Manager", and replace that with "Ms. Ting Zhou, Principal Supervisor".
And then one other change on the next page, page 29, starting on line 24, strike out "Mr. Brian V. Moccia, Manager - Advanced Metering Infrastructure Technical", and replace that with "Ms. Jacqueline L. Robinson, Director of Operational Technology". And those are my only changes.
Q Thank you. With those changes, is that the direct testimony that you are adopting today?
A Yes, it is.
Q Are you sponsoring any exhibits with your direct testimony?
A No, I'm not.
Q Did you also cause to be filed with the Commission a document titled the Rebuttal Testimony of Don Stanczak, consisting of a cover page and 11 pages of questions and answers?

A Yes.
Q Do you have any changes you wish to make to that rebuttal testimony?
A No.
Q Is that, then, the rebuttal testimony that you are adopting today?
A Yes, it is.
Q Are you sponsoring any exhibits with your rebuttal testimony?
A No, I'm not.

MS. HAYDEN: With that, your Honor, DTE Electric moves to bind into the record the qualifications, direct testimony, and rebuttal testimony of Don Stanczak, and tenders Mr. Stanczak for cross.

JUDGE WALLACE: Any objections to binding in the direct and rebuttal testimony of Mr. Stanczak?

(No response.)

Hearing none, Mr. Stanczak's direct and rebuttal testimony are bound into the record.

(Testimony bound in.)

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	))))))	Case No. U-20162

QUALIFICATIONS

AND
REVISED
DIRECT TESTIMONY

OF

DON M. STANCZAK

DTE ELECTRIC COMPANY
QUALIFICATIONS OF DON M. STANCZAK

Q. Please state your name, business address and by whom you are employed.

A. My name is Don M. Stanczak. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC a subsidiary of DTE Energy as Vice President, Regulatory Affairs.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q. What is your education background?

A. I received a Bachelor of Science Degree in Business Administration, with a major in Finance, from Central Michigan University. In addition, I received a Master of Business Administration Degree, with a major in Accounting, from Wayne State University.

Q. What work experience do you have?

A. I joined Michigan Consolidated Gas Company (MichCon) in 1983 and through 1994 had several assignments of increasing responsibility in a number of areas within MichCon, including Financial Services, Regulatory Affairs, Corporate Planning, Gas Supply and Supply Chain. In 1994, I was promoted to Director, Market Planning. In 1999, I transferred to Gas Transmission and Resource Planning as Director. In 2000 I moved back to Regulatory Affairs as Director, responsible for all of MichCon's regulatory activities. In 2001, MichCon's parent, MCN Energy, was acquired by DTE Energy, DTE Electric's (formerly Detroit Edison) parent. In 2005, I transitioned my responsibility to Director for DTE Electric's regulatory activities. In 2013, I assumed my present position having

responsibility for the development and implementation of regulatory strategy and administration for both DTE Electric and DTE Gas (formerly MichCon).

Q. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A. Yes. I sponsored testimony in the following DTE Electric, Detroit Edison, DTE Gas, and MichCon cases:

U-10544	MichCon Facility Application
U-10547	MichCon Facility Application
U-10744	MichCon Conservation Plan
U-10640	MichCon GCR Plan
U-10915	MichCon GCR Plan
U-11145	MichCon GCR Plan
U-12762	MichCon GCR Suspension Termination
U-13060	MichCon GCR Plan
U-13060-R	MichCon GCR Reconciliation
U-13549-R	MichCon GCR Reconciliation
U-13808	Detroit Edison Rate Case
U-13898	MichCon Rate Case
U-13933	Detroit Edison Low-Income Credit
U-14399	Detroit Edison Rate Unbundling
U-14428	Detroit Edison Other Post Employment Benefit Equalization Mechanism
U-15768	Detroit Edison Rate Case
U-16472	Detroit Edison Rate Case

U-16489	Detroit Edison deferred pension and post-employment benefits expense for future amortization and recovery
U-16780	Detroit Edison Revenue Decoupling Mechanism Reconciliation
U-16952	Detroit Edison 2011 Choice Incentive Mechanism Reconciliation
U-17437	DTE Electric PLD Transitional Cost Recovery Plan
U-17689	DTE Electric Public Act 169 of 2014 Filing
U-17767	DTE Electric Rate Case
U-17999	DTE Gas Rate Case
U-18014	DTE Electric Rate Case
U-18248	DTE Electric Capacity Charge Case
U-18255	DTE Electric Rate Case
U-18419	DTE Electric Certificate of Necessity

DTE ELECTRIC COMPANY
DIRECT TESTIMONY OF DON M. STANCZAK

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Q. What is the purpose of your testimony?

A. The purpose of my testimony is to:

- Provide an overview of the Company's entire rate case;
- Review the overall methodology used to develop the Company's projected test year amounts in this case;
- Review the Company's proposed Capacity Charge modification;
- Address the status of the Company's pending depreciation case and the impact on this case and future DTE Electric rate cases;
- Provide an overview of DTE Electric's proposal for an Infrastructure Recovery Mechanism (IRM) which is designed to recover the revenue requirement associated with certain capital expenditures through 2022;
- Describe the proposed rate making treatment and planned securitization of costs associated with the Company's tree trimming surge;
- Discuss the status and consequences of the Commission's directive that the Company establish time based rates for all residential customers; and
- Introduce the Company's other witnesses.

Q. Are you sponsoring any exhibits in this proceeding?

A. No, I am not.

Case Overview

Q. What is DTE Electric's overall business objective?

A. DTE Electric's overall business objective is to provide safe, reliable and cost effective electric service to its customers and deliver reasonable and appropriate compensatory returns to DTE Energy shareholders while maintaining its financial

health.

Providing safe, reliable and cost effective service to its customers means that DTE Electric: 1) provides quality customer service, 2) operates its system safely, and 3) delivers electric service reliably at a reasonable cost. The Company believes that providing our customers with quality customer service entails accurately billing our customers, ensuring our customers have ready access to a qualified customer service representative, and responding to customer inquiries and service orders in an efficient and effective manner.

Maintaining DTE Electric's financial health requires that the Company has a reasonable opportunity to earn its cost of capital, that the Company has a well-balanced capitalization (no less than 51% equity to total permanent capitalization), and that the Company is able to maintain its A/Aa3/A credit ratings for senior secured debt from the three major rating agencies. These preconditions are necessary to ensure DTE Electric's full access to capital markets at reasonable rates, terms and conditions regardless of business cycle timing or industry conditions. As discussed by Company Witness Mr. Solomon, without full access to capital markets at reasonable terms and conditions, the cost of providing utility services can increase significantly.

Thus, it is essential to DTE Electric's financial health that the ultimate cost that customers are asked to pay for Company services generates sufficient cash flow from operations to fund capital expenditures and pay a reasonable dividend.

Q. What rate relief was provided by the Commission's Order in the Company's last rate case, Case No. U-18255?

A. The Company's last general rate case, Case No. U-18255, was filed in April 2017 requesting $231 million in rate relief. On November 1, 2017, DTE Electric self-implemented a rate increase of $125 million. On April 18, 2017, DTE Electric received rate relief in the amount of $65.2 million in Case No. U-18255.

Q. Why has DTE Electric filed this general rate case?

A. The Company has carefully considered the need for filing this case. While I am aware of the impact that utility rate changes have on our customers, I am similarly aware that our customers expect and deserve safe and reliable service. DTE Electric's current authorized rates are not expected to provide DTE Electric with a reasonable opportunity to earn a fair return on equity beginning in May 2019. The Company continues to make improvements to its distribution and generation fleet in order to improve reliability and our customers' experience using our product. The only way that DTE Electric can adequately provide the required service levels that our customers desire and deserve is by being financially healthy. In order to attract the capital necessary for the prudent operation of our facilities, the Company must be able to demonstrate its ongoing financial health. Inadequate rates will ultimately result in higher financing costs, and will have a significant negative impact on our ability to adequately serve our customers and maintain the integrity of our electric distribution and generation assets. This negative impact will occur because more dollars are required to support our financing costs, and therefore are not available for system maintenance or customer service. Similarly, inadequate funding for capital and maintenance programs, over time, will result in the deterioration of DTE

Electric's generation and distribution infrastructure, ultimately resulting in reduced system reliability.

Q. Does the financial stability of DTE Electric provide additional benefits to customers and the region?

A. Yes. DTE Electric has an important positive economic impact on the communities it serves. DTE Electric is one of the largest employers in Southeast Michigan with over 4,800 employees; and through the Pure Michigan Business Connect campaign, the Company utilizes the services of numerous local contractors and vendors. DTE Energy spent over $1.65 billion with Michigan based companies in 2017. In addition, through property taxes, DTE Electric contributes to the financial health of the communities in which it serves; in the historical test year, DTE Electric paid about $250 million annually in property taxes to Southeast Michigan communities. Further, to maintain facilities and comply with various regulations, and related to the implementation of our Renewable Energy Plan, DTE Electric continues to make major capital investments in the communities in which it serves and operates. Thus, DTE Electric supports additional job growth opportunities and provides incremental tax revenue for the communities it serves.

Q. Has DTE Electric taken steps to minimize the impact on the need for rate relief in this proceeding?

A. Yes. DTE Electric has taken a number of actions to minimize, to the extent possible, the amount of rate relief required. In order to moderate the required rate increases to our customers, DTE Electric has in the past, and continues to aggressively pursue opportunities to reduce costs. DTE Electric has proactively

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engaged in a number of efforts to improve processes and to reduce costs as much as possible while still providing safe and reliable service to its customers. As noted by Company Witness Mr. Cooper, the Company's collective bargaining agreements and general market-driven wage increases result in expected annual escalations in wages of about 3%. Further, wages and contractor costs represent about two thirds of the Company's O&M expense. Therefore, the Company's ability to manage O&M in the past has been exceptional, particularly in light of the annual wage escalation I just noted. Unfortunately, the Company cannot continually reduce non-labor O&M in order to offset wage growth. Moreover, as addressed by a number of other Company witnesses, DTE Electric is experiencing inflation pressure relative to non-labor costs.

Q. What rate relief is DTE Electric requesting in this case?

A. As Company Witness Mr. Slater summarizes, DTE Electric expects a revenue shortfall of $328 million for the May 1, 2019 through April 30, 2020 projected test year. The key factor contributing to this shortfall is the revenue requirement associated with increased investments made in plant, working capital and associated depreciation and property tax increases, plus an increase in O&M.

<u>Rate Case Methodology</u>

Q. What approach is the Company using to support its projected test year positions and its recommendations in this case?

A. Although 2008 Public Act 286 allows for fully projected future test periods in setting utility rates, DTE Electric has used actual historical data as the point of departure for most estimated cost levels for the projected test year. These historical

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costs were then adjusted for the impact of inflation. As has been the Commission's practice in prior cases, certain other costs reflect specific estimates or projections where general impacts of inflation alone would not be appropriate. For example, some of these include, but are not limited to, capital expenditures, uncollectible expense, injuries and damages, pension and other post-employment benefits. All these cost components are supported by other Company witnesses.

Q. What historical and projected test year periods are being used by DTE Electric for purposes of calculating its projected revenue deficiency?

A. The historical test year used by DTE Electric is the calendar year ended December 31, 2017. This 12-month period was then normalized and adjusted for known and measurable changes, as supported by the Company's witnesses in this case, to arrive at the Company's May 1, 2019 through April 30, 2020 projected test year.

<u>Capacity Charge</u>

Q. Is the Company proposing to apply the same capacity charge to all of its customers regardless of whether they are on Choice or are bundled service customers?

A. Yes. As required by 2016 Public Act 341 (PA 341), and as more fully addressed by Company Witness Mr. Lacey, all customer classes will be allocated the same amount of generation capacity costs and all similarly situated customers, both Choice and bundled service will pay the same rate for generation capacity. That is, all Choice and bundled service customers paying for capacity will pay the same rate.

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Q. Is it reasonable for Choice customers to pay the same full embedded cost of DTE Electric's generation fleet as bundled customers even though the Choice customers are buying their energy from a third party?

A. Yes, it is reasonable for Choice customers to pay the same full embedded cost of DTE's electric generation fleet as bundled customers even though Choice customers are buying their energy from a third party. Not only is it reasonable for Choice customers to pay the same rate for capacity as bundled customers I believe it is expressly required by Section 6w(3) of PA 341. The service reliability provided by DTE Electric's generation capacity is the same for the Choice customers as it is for bundled customers. With the exception of its interruptible services, the Company serves all customers, bundled and Choice, with the same level of service relative to generation capacity.

Q. Specifically, what generation costs are reflected in the Company's proposed capacity charge?

A. I have directed Witness Lacey to include all Production related costs except fuel, variable O&M and certain purchase power costs in the capacity charge. This is the same methodology the Company proposed in its last rate case, Case No. U-18255.

Q. What types of capacity related costs are included in purchase power?

A. The Company pays capacity costs related to its PURPA/PA2 contracts and renewable energy resources; both company owned and related to purchase power agreements. Company Witness Mr. Arnold determines these costs.

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Q. Are the generation capacity costs you just described consistent with the requirement of PA 341?

A. Yes. Witness Lacey has included all capacity related generation costs included in DTE Electric's base rates, surcharges and power supply cost recovery cases consistent with PA 341, section 6w (3) (a). These costs do not include fuel, variable O&M, nor non-capacity purchased power expenses. The proceeds of energy market sales, net of fuel, are subtracted from those costs.

Q. Is the Company assuming that any Choice customers are paying the capacity charge?

A. For purposes of determining the capacity charge in this proceeding, the Company is assuming that zero Choice load will take capacity service from DTE Electric during the projected test year since earlier this year Choice providers demonstrated that they had the required capacity necessary to serve their customers through 2021.

Q. How frequently do you expect that the capacity charge will be modified by the Commission?

A. Generally, any base rate or PSCR factor change will change the capacity charge rates. Additionally, each year the Commission must conclude a proceeding by December 1 to review the capacity charge.

Q. In light of the December 1 required review you just addressed, when would you propose new capacity charge rates, pursuant to such a review, be implemented?

A. I propose that the capacity charge rates established by the Commission pursuant to the required December 1 review become effective on January 1st of the next year. There are costs and revenues in the capacity charge and the PSCR that are directly related. The PSCR operates on a calendar year basis, as such, administrative efficiency will be achieved by reflecting PSCR changes in the capacity charge on a calendar year basis and then reconciling them contemporaneously for that same calendar year.

Depreciation

Q. When did the Company file its most recent depreciation case?

A. As required by a prior Commission order, the Company filed a depreciation case on November 1, 2016, in Case No. U-18150. In addition, on November 10, 2016 the Company filed a joint depreciation case with Consumers Energy Company in Case No. U-18195 for the Ludington Pumped Storage Plant.

Q. Has the Company reflected the new depreciation rates that are the subject of Case Nos. U-18150 and U-18195 in this rate case?

A. Yes. The Commission has issued a final order approving a settlement in the Ludington Pumped Storage Plant deprecation case, Case No. U-18195; those new Commission approved depreciation rates are reflected in this case. However, the Commission has not issued a final order in Case No. U-18150, therefore, the Company has not reflected the impact of any potential change from the Company filed depreciation rates that could result from a final order in that case in this proceeding. Rather, the Company has reflected in this case the new depreciation rates as proposed in its application in Case No. U-18150.

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Q. Is it likely that a final Commission order will be issued in Case No. U-18150 prior to the conclusion of this rate case?

A. Exceptions to the Proposal for Decision (PFD) were filed in Case No. U-18150 on May 22, 2018, therefore, it seems likely that a final order in Case No. U-18150 will be issued before the conclusion of this rate case. Further, should new deprecation rates be established in a Commission order in Case No. U-18150 before the conclusion of this rate case, the Company proposes that those new depreciation rates be reflected in the retail rates established in this proceeding. This timing of the effective date of the new depreciation rates is consistent with the treatment requested by the Company in Case No. U-18150 and past Commission policy. That is, the new depreciation rates are implemented concurrent with the issuance of the first rate case order subsequent to the completion of the depreciation case.

<u>Infrastructure Recovery Mechanism</u>

Q. Is the Company proposing an Infrastructure Recovery Mechanism (IRM) in this case?

A. Yes. As supported through the testimony of Company Witnesses, Mr. Bruzzano, Mr. Davis, and Mr. Paul, the Company is proposing recovery of the incremental revenue requirement associated with certain distribution, fossil generation and nuclear generation capital expenditures through 2022 in this proceeding. Company Witness Ms. Uzenski summarizes the capital proposed to be covered by the IRM, and Witness Mr. Slater addresses the revenue requirement associated with the proposed IRM capital expenditures through 2022. Finally, Company Witness Mr. Bloch addresses the rate design and proposed rates associated with the IRM.

Q. Why is the Company proposing an IRM in this proceeding?

A. This current rate case is the fourth rate case in the last five years for DTE Electric. The Company's need for rate increases has been and is expected to be largely driven by its need to replace critical infrastructure required to safely and reliably serve our customers. The Company believes, with the proper IRM in place for the intervening years, it may be able to defer filing for a rate increase until sometime in 2022 for new base rates in 2023. Deferring the need to file rate cases should reduce the workload at the Commission and should result in a reduction in costs for all the parties that typically participate in Company rate cases. In addition, the systematic implementation of IRM surcharges should allow for more orderly and potentially smaller rate increases than what would occur if the Company continued to file rate cases, which should be beneficial for our customers. Finally, as more fully covered by Company Witnesses Bruzzano, Davis, and Paul, the IRM will support critical infrastructure improvements that will benefit our customers for years to come. In addition, some level of certainty relative to cost recovery should allow for the more efficient deployment of capital.

Q. If an IRM is approved by the Commission in this proceeding, is the Company guaranteeing that it will be able to defer filing a rate case until 2022?

A. No. The Company faces many cost pressures, beyond the capital expenditures that would be covered by the proposed IRM, that may require the Company to file a rate case before 2022 even if the proposed IRM is adopted by the Commission in this proceeding.

Q. What other cost pressures could impact the Company's ability to defer filing a

rate case until 2022 even if the proposed IRM in this proceeding is approved by the Commission?

A. There are several cost and revenue areas, beyond the capital expenditures covered by the proposed IRM, that could make it difficult for the Company to defer filing a rate case until 2022. These include incremental capital expenditures that are not included in the IRM, O&M general inflation or other O&M cost increases, reductions in sales and finally any other unforeseen external events.

Q. Specifically how will capital expenditures that are not included in the IRM impact the Company's ability to defer filing a rate case?

A. Generally the capital expenditures that are proposed to be recovered in the IRM are capital expenditures that are above and beyond replacement capital. I define replacement capital as capital expenditures that approximate annual depreciation expense. Thus, the Company is not seeking IRM treatment for normal capital expenditures that effectively are replacing capital that is being depreciated. Rather, the Company is seeking IRM treatment for capital expenditures that are above and beyond replacement capital. In the context of revenue requirement, replacement capital essentially backfills the decline in rate base due to the normal depreciation of gross plant. Therefore, theoretically, replacement capital has no impact on net rate base and thus no incremental return on rate base is associated with replacement capital. However, since depreciation and property tax expense are effectively based on gross plant, the Company experiences an increase in revenue requirement associated with these cost components even relative to replacement capital expenditures. Finally, any capital expenditures beyond replacement capital, that is not included in the IRM, will increase required return, deprecation and property tax.

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Q. Specifically how could O&M costs impact the Company's ability to defer filing a rate case?

A. Since O&M is not included in the IRM, the Company will be required to absorb any inflation or other cost increases that occur during the pendency of the IRM in order to defer filing a rate case. As summarized by Witness Ms. Uzenski, the Company's proposed O&M for the projected test year is $1.3 billion. Therefore, even if the Company experiences general inflation of two percent for example, it will have to absorb about $26 million annually. Similarly, any other potential O&M increase beyond inflation, such as increases in uncollectibles or employee benefits, will need to be absorbed by the Company in order to defer filing a rate case until 2022.

Q. Beyond the incremental capital and O&M increases you just described, what other issues could force the Company to seek rate relief prior to 2023 even if the IRM, as proposed in this case, is approved by the Commission?

A. Either a material decline in sales or some other external event, such as a change in relevant legislation, could necessitate filing for a rate increase prior to 2023.

Q. Specifically when and how will the IRM be implemented?

A. As noted earlier in my testimony, the projected test year in this proceeding is May 1, 2019 through April 30, 2020, therefore, the IRM is proposed to cover certain capital expenditures incurred beginning May 1, 2020 through December 31, 2022. To that end, the Company proposes that the initial IRM surcharge be implemented January 1, 2020 which would cover capital expenditures from May 1, 2020 through December 31, 2020. As more fully addressed by Witness Mr. Slater, the initial IRM will also include the second half of capital expenditures for the projected test year. Similarly,

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incremental IRM surcharges will be implemented January 1, 2021 and 2022, for the IRM capital expenditures for those calendar years. See Witness Bloch's testimony for a description of the surcharge design.

Q. Is the Company proposing that the IRM surcharges be reconciled?

A. Yes. The Company is proposing that the IRM surcharge be reconciled. More specifically, the Company is proposing that if the Company does not spend all the capital that is reflected in the IRM surcharge, the Company will refund the IRM surcharge revenue associated with that under spending. However, any incremental spending, beyond the level approved by the Commission, would not result in any incremental surcharge.

Q. Is the Company also proposing to reconcile the IRM dollars collected?

A. Yes. The Company is also proposing the revenue collected through the surcharge be reconciled. That is, if the Company over or under recovers the revenue that should have been recovered in the IRM surcharge, the Company will refund or surcharge that difference at the conclusion of the IRM. However, in no event will the Company be allowed to recover more than the maximum amount of revenue defined by the operation of the IRM. That is, if the Company under spends capital, the total amount of revenue recoverable will be reduced based on that under spend. In summary, the Company is effectively proposing an asymmetrical reconciliation relative to capital spend and a symmetrical reconciliation for revenue recovery up to the maximum allowed revenue based on the operation of the IRM.

Q. How does the Company propose to address any over or under recovery of

surcharges?

A. The Company proposes that any over or under recovery of the IRM be deferred as a regulatory liability or regulatory asset until the next IRM reconciliation. Once the IRM is terminated, the Company proposes there be one final reconciliation, which would result in a refund or surcharge. This is essentially the same over or under recovery reconciliation methodology already in use for the Company's Transition Reconciliation Mechanism (TRM) relative to the transition of Detroit Public Lighting Department (PLD) customers to DTE Electric service. Short term interest should be accrued on any over or under recovery.

Q. When does the Company propose that the interim reconciliations occur?

A. The Company proposes that the initial reconciliation be filed by April 30, 2021 for the capital expenditures from May 1, 2020 through December 21, 2020. Similar reconciliations will be filed by April 30 of the subsequent years for 2021 and 2022.

Q. When does the Company propose that the IRM surcharge(s) be terminated?

A. The Company is proposing that the IRM operate until a final order is issued in its next rate case. Accordingly, the Company proposes that any surcharges implemented pursuant to the IRM remain in effect until a final order is issued in the Company's next rate case and new base rates are implemented.

Q. Generally, what type of cost of service and rate design is being proposed relative to the IRM surcharges?

A. The cost of service methodology relative to IRM rate base will follow the same cost of service methodology as other similar capital that is reflected in base rates. Witness

Lacey addresses the cost of service allocation for the proposed IRM. For residential and small commercial customers, the Company is proposing a per kWh charge. For large commercial and industrial customers on rate schedules with a demand component, the Company is proposing an IRM demand charge. Company Witness Bloch address the rate design in detail and rates for the IRM.

Q. Is the Company proposing to report on the projects or units of work completed relative to the IRM?

A. Yes. The Company believes that it is essential that not only the capital dollars approved in the IRM be spent, but also that the capital is spent efficiently and effectively. As I will address later in my testimony, the Company is proposing that each fall the Company and Staff meet to review expected IRM expenditures and the scope of IRM work to be accomplished for the upcoming IRM year. The Company is proposing that actual work completed will be summarized and provided to Staff in the reconciliation. These are described in Company Witnesses Bruzzano, Davis and Paul's testimony as Program Metrics.

Q. Are there any other metrics the Company will report to allow the MPSC to assess the benefits of the programs in the IRM?

A. Yes, as described by Company Witnesses, Bruzzano, Davis and Paul, the Company is proposing to include specific results of program metrics in the annual reconciliation. Additionally, Company Witnesses, Bruzzano, Davis and Paul, describe specific performance indicators that the Company is proposing to be reported annually to the MPSC Staff.

Q. What type of additional review, if any, is the Company proposing regarding the IRM?

A. The Company proposes that every fall prior to the IRM year, the Company meets with the Commission Staff to review specific spending and projects as well as measures. In addition, the Company proposes to meet with Commission Staff throughout the year to review progress relative to the plan.

Q. Is the Company proposing that there be any flexibility in the amount spent on any particular capital expenditure category?

A. Yes. The Company proposes that within distribution, generation and the proposed combined cycle natural gas plant, the Company be allowed some flexibility. However, the Company is not seeking to move any capital between those three broad business units. Within those business units, the Company is proposing to be able to move up to 20 percent of the capital dollars to or from any discrete category of work as defined on Exhibit A-30 T2, T3 and T4.

Tree Trimming Surge

Q. What is the Company proposing with respect to tree trim expenditures in this case?

A. DTE Electric is proposing to increase its tree trim expenditures significantly above its average spend over the last three years to eliminate the backlog of necessary work. As discussed in detail by Company Witness Ms. Rivard, this “surge” in tree trimming spending will occur over a seven-year period, and at its termination the Company expects to maintain a steady-state five-year cycle of tree trimming.

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Q. Is the Company seeking recovery of the tree trimming surge expense in the O&M levels in its projected period revenue requirement?

A. No. DTE is seeking approval in this case to defer the surge related expenses as a regulatory asset, which will be securitized when that asset reaches an appropriate balance. The securitization of the deferred expense is discussed by Company Witness Solomon.

Q. Why is it appropriate to defer and then securitize the surge related tree trimming expenses?

A. The surge related tree trimming expenses will vary, so allowing the deferral of the expenditures above the level that is included in the rates approved in this case will ensure that customers only pay for the work that is accomplished. Additionally, the benefits provided by the surge will continue for years after the work is completed. Allowing these costs to be deferred and then securitized with a 14 year amortization period will better match those benefits to the recovery of the cost. Finally, the securitization of these deferred expenses will lower the cost to our customers due to lower-cost of debt only financing.

<u>Rate Schedule D1 Time of Use</u>

Q. Are you familiar with the Commission's Order in Case No. U-18255 issued on April 18, 2018, and in particular the required change in the residential rate structure for Rate Schedule D1?

A. Yes I am. In the April 18, 2018 order in Case No. U-18255, the Commission ordered the Company, in its next general rate case, to include proposed tariffs for non-capacity charges based on summer on and off peak rates. In other words,

approximately 1.9 million residential customers will be defaulted to time based rates for non-capacity charges. Note, the capacity charge component of customers' rates will be unchanged.

Q. Did the Company file for rehearing of this issue in Case No. U-18255?

A. Yes. In its rehearing, the Company stated that the directive to move approximately 1.9 million customers to a time-based rate will have unintended consequences, and therefore requested that the Commission reconsider this requirement. The Company already offers several optional rates to its residential customers which incorporate time of day and seasonal pricing; however, the Commission's directive to convert Rate Schedule D1 to a time of use rate structure would force all residential customers to be subject to time of use pricing. This will have a significant impact on the Company's rate structure and on the individual bills of the approximately 1.9 million Rate Schedule D1 residential customers.

Q. Specifically what relief did DTE Electric seek in its rehearing request?

A. The Company requested that the Commission eliminate the requirement to move all residential customers to time of use rates. In the alternative, the Company proposed that the Commission require the Company to file a proposed plan or process to transition its Rate Schedule D1 non-capacity rate to a time of use rate structure over a reasonable period of time. This would allow the Company to have more time to analyze and determine the best way to develop and implement such a fundamental change. Such a transition plan would also provide for appropriate customer communication as well as the evaluation of potential changes in customer behavior due to the expanded use of time of day rates.

Q On June 28, 2018, the Commission issued an order on rehearing in U-18255. What was their response to the Company's rehearing request on this issue?

A. The Commission denied DTE Electric's petition for rehearing on this issue and affirmed that new non-capacity rates for Rate Schedule D1 should be based on summer on-peak rates. However, the Commission properly recognized that moving approximately 1.9 million residential customers to a time-based rate is a significant change to our business and our customers, by stating it "should be thoughtfully implemented, and does not view the decision in this case as foreclosing consideration of implementation issues related to timing or costs in future rate case" (June 28, 2018 Order, page 7).

Q What impact will moving to default time based rates for essentially all residential customers have on residential customers and the Company?

A. First, relative to customers, they should be allowed to choose to opt-in voluntarily to any new and significantly different rate program the Company offers. By offering several different residential rates as we do today, customers have a wide range of options, including whole home time of use rates, interruptible air conditioning, dynamic peak pricing, and geothermal rates. If customers believe they can take advantage of savings related to a time of use rate structure, or any other rate program, customers will opt-in, however customers should not be forced on to time of use rates. For the Company, this change in residential rate structure will impact a number of areas including Information Technology, Customer Service, and Marketing and Communications. These impacts, both operational and financial are discussed further by Company Witnesses Mr. Griffin, Ms. Johnson, and Mr. Clinton, respectively.

Q What is the Company's recommendation in this case related to changing Rate Schedule D1 to having a time-based charging component?

A. In addition to the significant costs and extended timing issues as discussed by Witnesses Clinton, Johnson, and Griffin related to implementing this new rate structure, as stated above, the Company believes it currently has sufficient time-based rate products available to customers who desire to opt-in. Therefore, the Company continues to support its position taken in Case No. U-18255, and requests that the Commission in the final order in the present case, reverse its previous ruling from Case No. U-18255 and allow the Company to retain its existing Rate Schedule D1 pricing structure (with no time-based element). If the Commission does not grant this request, the Company must be allowed to proceed with implementation over a reasonable time period given the scope of work involved, and be allowed to recover all costs associated with this implementation consistent with Witness Uzenski's testimony.

Q What has the Company proposed from a rate design perspective in this case related to its Rate Schedule D1?

A. As Company Witness Mr. Dennis states in his testimony, DTE Electric has complied with the Commission's directive to develop a time-based rate for Rate Schedule D1. He also proposes rates based on the Rate Schedule D1 as it traditionally has been designed. He does this for two reasons. First, in anticipation that the Commission will reverse its prior decision and allow the Company to retain its existing Rate Schedule D1 pricing structure (with no time-based element) in the final order in the present case. Second, even if the Commission chooses to not reverse its prior decision, the existing rate structure needs to stay in place until such

a time as all customers can be transitioned to the new rate structure given the long lead time needed to facilitate this change company wide.

Introduction of Other Witnesses

Q. How will the Company present evidence in support of its positions in this case?

A. The Company proposes to present its case through 27 witnesses, including myself, as described below (in alphabetical order).

1) Mr. Derek M. Arnold, Supervisor – Strategic Merchant Analytics, establishes the capacity-related generation costs included in the Company's Power Supply Cost Recovery Factor and the benefit of energy and ancillary services sales from the Company's capacity resources.

2) Mr. Timothy A. Bloch, Principal Financial Analyst – Pricing, supports the Company's proposed primary customer rate design and other proposed tariff changes as well as the IRM rate design and proposed rates.

3) Mr. Marco A. Bruzzano, Vice President – Distribution Operations supports the historical capital expenditures and Operations and Maintenance expenses related to electric distribution efforts for 2017 and the projected capital expenditures and O&M expenses for 2018 through April 2020. He will describe the major segments and driving forces behind this spending and discuss the organizations that incur these costs. Additionally, he will support the capital expenditures in the period beginning on May 1, 2020 and ending on December 31, 2022 that the Company is proposing to be included in its IRM.

4) Mr. Eric W. Clinton, Manager Electric Sales and Marketing – will provide details on the Company's Electric Vehicle (EV) education and development

programs; provide details around two new pricing pilot programs for residential customers and; provide details and support for the Regulated Marketing O&M Expense.

5) Mr. Michael S. Cooper, Director - Compensation, Benefits & Wellness, presents an overview of benefit expense for DTE Electric for the 2017 historical test period and the May 1, 2019 through April 30, 2020 projected test period. He will provide support for the Company's pension costs, other post-employment benefits ("OPEB"), active employee health care costs and other employee benefits; provide an overview of the Company's compensation philosophy for non-represented employees and the role that the Company's incentive plans play in the overall reasonableness of its total compensation policies; describe the components of the Company's short and long-term incentive plans and support the inclusion of such costs in the Company's revenue requirement, exclusive of the costs related to DTE Energy's top five executives: and demonstrate the quantifiable customer benefits of the Company's incentive plans exceed the expense, as required by the Commission's traditionally mandated cost/benefit analysis of incentive compensation expense.

6) Mr. Jeffery C. Davis, Manager – Nuclear Strategy and Business Support, will support the Company's actual O&M and capital nuclear expenditures for the 12-month historical test year ended December 2017. He will also discuss and support the projected nuclear O&M and capital expenditures for the interim forecast period and a twelve-month projected test period ending April 30, 2020. Additionally, he will support the capital expenditures in the period beginning on May 1, 2020 and ending on December 31, 2022 that the Company is

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proposing to be included in its IRM.

7) Mr. Philip W. Dennis, Manager, Regulatory Economics will support the proposed rate design for the residential customer rate schedules and the development of capacity charges for each residential rate schedule, pursuant to the requirements of 2016 PA 341 as well as the development of power supply non-capacity charges based on summer on-peak rates (i.e. Time of Use (TOU)) as required by the Commission's Order in Case No. U-18255.

8) Ms. Irene Dimitry, Vice President – Business Planning & Development, will support and justify the expenditures related to both DTE Electric's existing and future demand side management programs; and discuss the River Rouge Unit 3 economic analysis.

9) Mr. Keegan O. Farrell, Principal Financial Analyst - Load Research, will support and justify the development of the May 2019/April 2020 forecast allocation schedules; and the methodology DTE Electric used to include the demand associated with the Electric Choice loads in the forecast distribution allocation schedules; support and justify the hours used for the summer 6 on-peak non-capacity charge; and support and justify the anticipated load shift by residential customers in the Weekend Flex Pilot Program.

10) Mr. Robert D. Feldmann, Executive Director, Electric Sales and Marketing, will provide details on DTE Electric's investment in a pilot, Combined Heat and Power (CHP) plant that will be located on Ford Motor Company's (Ford) Research and Engineering (R&E) campus in Dearborn, Michigan, and the inclusion of that asset in the Company's rate base.

11) Mr. Daniel J. Griffin, IT Director of Operations & Infrastructure – supports the reasonableness of DTE Electric's IT capital expenditures for the historic test

year of 2017 as well as the projected capital spend from January 2018 through the end of the projected test period ending April 30, 2020; discuss DTE Electric's IT's planning process; and provide details on the impacts to the Company from emerging technology trends.

12) Ms. Kelly A. Holmes, Principal Financial Analyst – Regulatory Economics, will support the development of the proposed rate design for the secondary customer (mostly commercial) tariff offerings. She is also supporting the calculation of power supply costs for the Company's projected test period in this case. She will support power supply rates designed to include a capacity charge, pursuant to the requirements on 2016 PA 341 and consistent with the methodology used in Case No. U-18248 as instructed by the Commission in its Order in U-18255; and distribution rates designed to approach a uniform rate for all commercial secondary tariff offerings.

13) Ms. Tamara Johnson, Director – Revenue Management & Protection, will explain the details of the Company's Customer Service Operation and Maintenance (O&M) expenses for the 12-months ended December 31, 2017, and provide explanation and support of the projected O&M expenses for the 12-month projected test period ending April 30, 2020 inclusive of uncollectible expense. She will provide details for the historical costs, discuss the inflationary impact on forecasted costs, provide an update on our level of uncollectible expense, support proposed changes to merchant fees, discuss Customer Service performance and areas of improvement, discuss the Company's Low Income initiative, Customer 360 (C360) Project costs and proposed changes the Company's tariff.

Ms. Ting Zhou, Principal Supervisor

14) ~~Mr. Kenneth D. Johnston, Manager~~ – Community Lighting, will support the

energy forecast for outdoor lighting; the development of the proposed rate design for the outdoor lighting rate schedules (municipal lighting and other); support the reasonableness of the historic and projected Community Lighting O&M; discuss the Community Lighting capital expenditures; and the establishment of a post/pole charge.

15) Mr. Thomas W. Lacey, Principal Financial Analyst – Revenue Requirements Department, will present Unbundled Cost of Service (UCOS) Studies for DTE Electric's projected test year ending April 30, 2020. He also supports revenue requirement calculations for: (1) customer related costs, (2) capacity charge by rate class, and (3) Infrastructure Recovery Mechanism (IRM) by rate class.

16) Mr. Markus B. Leuker, Manager – Corporate Energy Forecasting, will provide the Company's current electric sales, maximum demand and system output forecast for the period 2018-2028, including the projected period for the 12 months ending April 30, 2020. He will discuss the outlook for the national and local economy which is the basis of the forecast. He will also describe how the forecast of electric sales, maximum demand and system output is developed and support the reasonableness of the electric sales forecast used by DTE Electric in this proceeding.

17) Mr. David C. Milo, Fuel Resource Specialist – Fuel Supply, will support DTE Electric Fuel Supply's and Midwest Energy Resources Company's operations and maintenance expense and capital expenditures for the twelve months ended December 2017 historical actual, and as projected for January 2018 through April 30, 2020.

18) Ms. Jacqueline L. Robinson, Director of Operational Technology ~~Mr. Brian V. Moccia, Manager – Advanced Metering Infrastructure - Technical~~, will support the reasonableness of DTE Electric's AMI project

from a benefit perspective. He will provide a brief background on the progress made with AMI and current status of completion; and will also provide testimony to discuss and support AMI 3G to 4G communication upgrade, AMI Industrial 4G communication upgrade, and AMI leveraged tools (PI, Analytics).

19) Mr. Matthew T. Paul, Vice President – Plant Operations, Fossil Generation, will explain DTE Electric's Fossil Generation planned changes in power plant capacity ratings; provide a review of the Fossil Generation base coal unit availability performance for five years prior and five years following the test year in this case; support the historical 2017 level of capital expenditures on a plant level basis and provide forecasts of capital expenditures planned for 2018 through April 30, 2020; support the known and measurable changes in Fossil Generation Operating and Maintenance expenses that will span the timeframe from the 2017 historic test year in this case to the projected test year, ending April 30, 2020; describe the new CHP unit;. finally, he will support the capital expenditures in the period beginning on May 1, 2020 and ending on December 31, 2022 that the Company is proposing to be included in its IRM.

20) Ms. Heather D. Rivard, Senior Vice President of Electric Distribution – will discuss the Company's tree trimming program including the 2017 historic period expense, and the expense for the projected test year; and support funding for a program structure that will enable the Company to deliver the reliability goals established in its Five-Year Plan.

21) Mr. Camilo Serna, Vice President of Corporate Strategy – will detail electrification of transportation in Michigan; describe and support the

Company's proposed EV program; and support the cost estimates of that program along with the associated approach for cost recovery.

22) Mr. Kenneth Slater, Manager - Revenue Requirement, will support DTE Electric's twelve months ended December 31, 2017 historical revenue deficiency. In addition, he is sponsoring Net Operating Income ("NOI") adjustments for interest synchronization and income tax savings, as well as, the revenue conversion factor. Mr. Slater is sponsoring DTE Electric's twelve months ending April 30, 2020 projected revenue deficiency. Furthermore, he is sponsoring the NOI adjustments for interest synchronization and income tax savings as well as the projected revenue conversion factor. He is also calculating the incremental revenue requirement for DTE Electric's Tree Trim Surge Amortization request and the projected value of the Tree Trim Surge Program. In addition, he supports the calculation of the incremental revenue requirements for DTE Electric's Infrastructure Recovery Mechanism (IRM) and provides an example of the revenue requirement impact of an under spend in the IRM reconciliation.

23) Mr. Edward J. Solomon, Assistant Treasurer and Director – Corporate Finance, will support DTE Electric's projected capital structure; the cost of its long and short-term debt to be used in the determination of DTE Electric's overall rate of return; and the securitization of the Company's deferred surge-related tree trimming expenses.

24) Ms. Theresa Uzenski, Manager – Regulatory Accounting, will support DTE Electric's financial statements for the historical test year ended December 31, 2017, the interim forecast period and a twelve-month projected test period ending April 30, 2020, with certain adjustments necessary for presenting the

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financial information in the appropriate format for ratemaking purposes. She will support the development of the projected test year adjusted electric operating income based on forecasted changes from the normalized historical electric operating income. Ms. Uzenski will also support the Corporate Staff Group expenses for the historical and forecasted periods and explain the function of this group and the method for allocating costs to DTE Electric and the other DTE subsidiaries. She will support that costs recovered from other mechanisms are excluded from the financial statements in this case (including the Transitional Recovery Mechanism for the transition of Detroit Public Lighting Department customers, Renewable Energy Program, Energy Optimization, etc.). She will also request regulatory asset treatment for certain costs.

25) Dr. Michael Vilbert– A Principal at The Brattle Group, will estimate the cost of capital for the Company. Specifically, Dr. Vilbert provides return on equity (ROE) estimates derived from a sample of comparable risk, regulated electric utility companies. Dr. Vilbert also considers the relative risk of the Company's proposed capital structure ratio to arrive at his recommendation for the allowed ROE of 10.5%.

26) Ms. Sherri Wisniewski, Director – Tax Operations, will support the DTE Electric Federal Income Tax, Michigan Corporate Income Tax, Municipal Income Tax, property tax and other general taxes for the 2017 calendar year historical period and the twelve months projected test period ending April 30, 2020. She also proposes how re-measurement of deferred taxes resulting from Tax Cut Jobs Act 2017 will be returned to customers through amortization of the tax regulatory liability starting on May 1, 2019.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

REBUTTAL TESTIMONY

OF

DON M. STANCZAK

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF DON M. STANCZAK

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Q. Please state your name, business address and by whom you are employed.

A. My name is Don M. Stanczak. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC a subsidiary of DTE Energy as Vice President, Regulatory Affairs.

Q. Did you file direct testimony in this proceeding on behalf of the DTE Electric Company (DTE Electric or Company)?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the positions of the Michigan Public Service Commission (Commission or MPSC) Staff Witnesses Mr. Evans, Mr. Laruwe, and Mr. Revere relative to a proposed adjustment to distribution capital expenditures, the scope of the Company's Infrastructure Recovery Mechanism (IRM) investments and the recommendation of a Performance Based Rates (PBR) collaborative, and implementation of the Rate Schedule D1 summer on-peak rate. My rebuttal testimony will also address Attorney General (AG) Witness Mr. Coppola's proposed adjustment to projected inflation expenses in the test period and statements made relative to a rate case delay associated with the IRM. I will also rebut ABATE Witness Mr. Gorman's position that his proposed regulatory plan would not have a negative impact on the Company. Finally, my testimony addresses Soulardarity Witness Mr. Koeppel's recommendation to provide a comparison between potential generation resources in this proceeding.

The absence of a discussion of other matters in my rebuttal testimony should not be

taken as an indication that I agree with other aspects of any Staff or intervenor testimony.

Q. Are you sponsoring any rebuttal exhibits?

A. No, I am not.

REBUTTAL OF COMMISSION STAFF WITNESS EVANS

Q. In support of an adjustment to historical distribution capital expenditures, Staff Witness Evans, on page 9 of his direct testimony, states "However, a utility that over-spends its Commission authorization in a major category, like distribution plant, should justify this higher spending in the next rate case. Staff should not be caught unaware of over-spending in the historic year of a rate case." Is the proposed adjustment appropriate?

A. No. In a rate case proceeding, the Commission authorizes the Company's rates based on a revenue requirement including a reasonable rate of return, but it does not set fixed spending levels. In the current case, and in every DTE Electric rate case since 2008, the historical test year has been used and then normalized and adjusted for known and measurable changes to arrive at expenditures in the projected test period. That is, the projected test year is a projection of the expenditures that are likely to be made given the information known at the time of the rate case filing. Hindsight should not be used in the rate setting process to reconcile the difference between projected expenditures from a prior rate case against actual expenditures incurred in a historical period. Rather, the Company's test period expenditures should be evaluated for reasonableness and prudence.

Q. Are you suggesting that any and all capital expenditures incurred in the historical test year, or prior to the historical test year, should be automatically approved for recovery by the Commission and thus result in essentially guaranteed recovery?

A. No. However, the Company should have an opportunity to recover the cost of prudently incurred capital expenditures that reflect used and useful assets which have been deployed for the benefit of customers.

Q. Did Staff Witness Evans suggest that the Company's 2017 distribution capital expenditures were imprudent or unreasonable?

A. No. Staff Witness Evans cites no evidence that the Company's investments were unreasonable or imprudent. As supported by Company Witness Mr. Bruzzano in his direct and rebuttal testimony, the 2017 distribution capital expenditures were reasonably and prudently incurred for utility plant that is used and useful for the provision of utility service. Under general ratemaking principles, the Company is entitled to the return "of" and "on" its investments in providing utility service. Therefore, Staff's proposed adjustment to distribution capital expenditures in the historical test period should be rejected.

Company Witness Mr. Bruzzano will further rebut Staff Witness Evans regarding his statements concerning the lack of testimonial support and the pace of spending in 2018.

Q. On page 14 of his direct testimony, Staff Witness Evans states "Staff recommends that the Company should be directed to notify the Staff before a significant over-spend of Commission approved electric distribution capex occurs." Do you agree with this approach?

A. No. Witness Evans' recommendation that the Company notify the Staff *before* a significant over-spend (compared to projected test year amounts in a prior rate case) is a substantial change to the current regulatory construct. The Commission has authority to regulate DTE Electric's rates, but does not have the power to make management decisions concerning the Company's operational decisions and associated investments. DTE Electric makes investment decisions daily, often in real-time in response to emergent situations. It would be wholly inefficient, if not entirely inappropriate, that these investment decisions be subject to pre-review and/or pre-approval from the Commission Staff. Such an overreaching requirement into the day-to-day management of the Company would set a poor regulatory policy precedent and should be rejected.

However, the Company has and will continue to provide the Commission with information necessary to ensure proper regulatory oversight. Through new Part III rate case filing requirements and other recent proceedings such as our five-year distribution investment and maintenance plan (Case No. U-20147) and 2018 storm report (Case No. U-20169), the Company has been providing an unprecedented level of detail relative to historical and projected spending levels and operational plans, including expenditures made in 2017 and 2018.

REBUTTAL OF COMMISSION STAFF WITNESS LARUWE

Q. On page 6 of his direct testimony, Witness Laruwe states: "[T]he scope of the proposed IRM in this case exceeds investments for compliance and safety and therefore needs to be approached in a more cautious manner, to ensure all potential benefits are realized." Do you agree with Mr. Laruwe's assessment regarding the types of investments that should be included in the IRM?

A. No. Witness Laruwe claims that the scope of the IRM exceeds investments for "compliance and safety", but never defines those terms nor identifies which investments are outside of this undefined criterion. DTE Electric's overall business objective is to provide safe, reliable and cost effective electric service to its customers, and our planned investments in the projected test year and the IRM support this objective. As stated in my direct testimony, the IRM will support critical infrastructure improvements that will benefit our customers for years to come. The specific investments and associated benefits of the IRM are further supported by Company Witnesses Mr. Bruzzano, Mr. Davis, and Mr. Paul in their direct and rebuttal testimony.

Q. On page 7 of his direct testimony, Staff Witness Laruwe states, "Given the financial and regulatory implications that are associated with the implementation of PBR, the foundation for PBR is most appropriately developed outside of the context of the general rate case and should include open and transparent discussions with all energy stakeholders. In the Staff's distribution planning framework outlined in the September 1, 2018 report, Staff has recommended the Commission create a collaborative to facilitate these discussions." Do you agree with this approach?

A. No. Staff's September 1, 2018 report in Case No. U-20147 provides an excellent starting point for further discussion, investigation and collaboration regarding distribution planning. However, implementation of Performance Based Rates (PBR) and the associated measures and metrics would have significant financial, operational, and regulatory implications that are specific and unique to DTE Electric and our customers. Therefore, review of PBR is more appropriate within a general rate case proceeding, where both the measures/metrics associated with PBR and the Company's

planned investments can be reviewed in tandem. Although the Company could be supportive of a collaborative for a narrow group of interested stakeholders to review the theoretical concepts of PBR and implications for Michigan, it would be impractical and inefficient to develop the foundations and standards of PBR in such a forum.

REBUTTAL OF STAFF WITNESS REVERE

Q. On page 6 of his direct testimony and in Exhibit S-16.1, Staff Witness Revere addressees the Company's Recommended Plan and Alternative Plan relative to transitioning residential customers to a summer on-peak rate. Could you please describe the Company's Recommended Plan?

A. Yes. The Recommended Plan allows for piloting multiple rates to allow for a more comprehensive assessment of potential rate designs. This will help determine a rate design(s) that is best for our customers over the long-term. Given the significant costs and extended timing issues related to implementing a new rate structure, it is appropriate to assess and anticipate what other changes may be appropriate for the Company to best serve customers and offer additional options beyond the proposed summer on-peak rate. The Recommended Plan also allows for testing multiple messages among different customer groups and researching effective marketing and education.

Q. How does the Alternative Plan differ from the Recommended Plan?

A. The Alternative Plan allows for the piloting of only a single rate in phase one, whereas, the Recommended Plan allows for piloting multiple rates. Piloting only a single rate results in a projected go-live date of June 2021 compared to May 2022 for the Recommended Plan. The Alternative Plan provides less time to gather

information and study customer behavior due to summer on-peak rate changes, and to develop solutions to potential issues identified during the pilot phase.

The Company believes that we should obtain insight into customer interests during this transition to time of use rates. The Recommended Plan allows the Company time to work with its customers to introduce the Commission required time of use rates with the focus on minimizing any potential negative impact to our customers.

Q. In rejection of the Company's Recommended Plan and in support of the Alternative Plan, Staff Witness Revere on page 7 of his direct testimony states "Testing different rate designs in unnecessary." Do you agree?

A. No. It is important to get each customer on the right rate and provide for potential opt-in rate alternatives. The Company must analyze and understand the impacts to customers for whom a summer on-peak rate is not feasible or appropriate. For example, customers who cannot shift load without significant adverse impacts, customers who should not shift load due to unique health reasons, and customers who should be aware of other rate options. Therefore, it is necessary to pilot multiple rates and evaluate results to determine customer implications from a summer on-peak rate compared to other opt-in rate alternatives.

Further, it would be unfortunate to not utilize this rate transition period as an opportunity for a comprehensive assessment of rate design that benefits our customers in the long term.

Q. Did Staff Witness Revere provide any support for his conclusion that testing different rate designs is unnecessary?

A. No. Witness Revere does not provide any additional support regarding why testing different rate designs is unnecessary. In fact, his conclusion is contrary to the research and best practices provided in Staff Witness Revere's Exhibit S-16.1.

Q. Are there benefits to the Recommended Plan beyond providing the opportunity to test different rate designs?

A. Yes. Multiple policy goals and objectives may be achieved through a thoughtful and comprehensive rate design assessment that results in both new opt-in rate options and default rates. The Recommended Plan includes additional objectives and benefits, such as: 1) understanding customer behavior and peak load reduction and to assess feasibility and attractiveness of alternative rate designs; 2) billing analysis to determine appropriate on-peak/off-peak pricing ratio and impacts to customer affordability; and 3) testing multiple messages that encourage load shifting among different customer segments.

Q. On page 8 of his direct testimony, regarding the Company's proposal Rate Schedule D1 summer on-peak rates, Staff Witness Revere states, "In addition, the Company maintained the current rate structure for capacity charges. This is inappropriate. It is more appropriate to apply the same on- and off-peak definitions to the capacity charge as the non-capacity charge, rather than maintaining the inappropriate and unnecessary current structure." Do you agree?

A. No. Staff Witness Revere's recommendation is inconsistent with the Commission's Order dated April 18, 2018 in DTE Electric's last rate case, Case No. U-18255, which

found that the current rate design for capacity charges should be maintained and further directed the Company in its next general rate case filing to include proposed tariffs for *non-capacity charges* based on summer on-peak rates. Therefore, the Company's proposal to only convert the Rate Schedule D1 non-capacity charges to a summer on-peak structure is consistent with the Commission's order. Company Witness Mr. Dennis will further rebut the technical aspects of Staff Witness Revere's proposal.

<u>REBUTTAL OF ATTORNEY GENERAL WITNESS COPPOLA</u>

Q. On page 12 of his direct testimony, AG Witness Coppola states, "The Company has not provided any evidence that its operations are facing inflationary cost pressures that it cannot manage in the course of operating its business. Therefore, the proposed inflation cost increases are not likely to occur in the coming months as the Company will likely continue to manage its operations to offset the low level of forecasted inflation with increased operating efficiencies." Is this an accurate characterization?

A. No. AG Witness Coppola provides no support for his statement that "the Company will likely continue to manage its operations to offset the low level of forecasted inflation with increased operating efficiencies." Although the Company's ability to manage O&M in the past has been exceptional, the Company cannot continually reduce non-labor O&M in order to offset wage growth. Furthermore, AG Witness Coppola essentially ignores the fact that labor cost increases are driven in part by the Company's collective bargaining agreements and general market-driven wage increases, as supported by Company Witness Mr. Cooper. AG Witness Coppola's assertions regarding cost increases, resulting in almost zero inflation in the projected period, are unreasonable and unsupported and should be rejected.

Q. On page 67 of his direct testimony, AG Witness Coppola states, "Beginning on page 14 of his direct testimony, Mr. Stanczak seems to offer a proposal that the Company would delay filing another rate case until sometime in 2022. However, in the subsequent paragraph and pages, he explain [sic] why the Company is not likely to delay such a rate filing because of other cost pressures." Is this an accurate characterization of your direct testimony?

A. No. This is a mischaracterization of my direct testimony, as I never stated that the Company is "not likely" to delay a rate case. For example, on page 14 of my direct testimony I state, "The Company believes, with the proper IRM in place for the intervening years, *it may be able to defer* filing for a rate increase until sometime in 2022 for new base rates in 2023." *(emphasis added)* Further, on page 15 of my direct testimony I state, "There are several cost and revenue areas, beyond the capital expenditures covered by the proposed IRM, *that could make it difficult* for the Company to defer filing a rate case until 2022." *(Emphasis added)* However, the Company does believe, with the proper IRM in place for the intervening years, it may be able to defer filing for a rate increase until sometime in 2022 for new base rates in 2023.

<u>REBUTTAL OF ABATE WITNESS GORMAN</u>

Q. In support of his regulatory plan, ABATE Witness Gorman states on page 19 of his direct testimony "I believe this regulatory plan has benefits to both customers and the utility." Do you agree?

A. No, this proposal could harm both customers and the Company. As supported by Company Witness Mr. Solomon in his rebuttal testimony, the regulatory plan proposal would negatively impact DTE Electric's cash flows and potentially the Company's

credit ratings, and subsequently result in higher financing costs. Higher financing costs will have a negative impact on our ability to adequately serve our customers and maintain the integrity of our electric distribution and generation assets. This negative impact will occur because more dollars are required to support our financing costs, and therefore are not available for system maintenance or customer service.

REBUTTAL OF SOULARDARITY WITNESS KOEPPEL

Q. On page 31 of his direct testimony, Soulardarity Witness Koeppel states, "In particular, DTE should account for the difference in long-term benefits offered by the gas plant in contrast to renewable energy and how that compares to the costs that ratepayers must bear to build and maintain the new gas plant." Do you agree?

A. No. A comparison between potential generation resources is outside the scope of the current proceeding. A full analysis of generation resources will be addressed in the Company's upcoming 2019 Integrated Resource Plan (IRP) filing.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

JUDGE WALLACE: Before we get started, who has cross for -- I know that the Staff has cross for Mr. Stanczak, MEC. Anyone else? (Show of hands.)

MR. KING: Me, too, your Honor.

JUDGE WALLACE: Attorney General. GLREA or RCG?

MR. KESKEY: They're a combination, your Honor.

JUDGE WALLACE: Both, O.K. O.K. So Staff, Attorney General, MEC, GLREA, RCG. Anyone else? (No response.)

All right. We'll begin with you, Mr. Singh.

MR. SINGH: Your Honor, Staff would prefer to go after the other parties who have cross.

JUDGE WALLACE: All right. That's fine. And then --

MR. KESKEY: Your Honor, we would be second to last.

JUDGE WALLACE: Well, it is a race to the bottom or something here. Would MEC and the AG like to like wrestle for this?

MR. KING: I can do it, I can go first, your Honor.

JUDGE WALLACE: Thank you. Go ahead,

Mr. King.

CROSS-EXAMINATION

BY MR. KING:

Q Good morning, Mr. Stanczak.

A Good morning.

Q Joel King with the Attorney General. Mr. Stanczak, as Vice President of Regulatory Affairs for DTE Energy Corporate Services, is it fair to say that you are the individual who has overall responsibility for the Company's rate case filings?

A Yes.

Q And you had those same responsibilities for the Company's two prior rate cases, Case Nos. U-18255 and U-18014, correct?

A Yes.

Q And you are also the main witness for the Company on major regulatory policies and cost recovery positions taken by DTE in rate cases, correct?

A Yes.

Q So in your role, you are generally familiar with O&M inflation cost recovery positions taken by other Company witnesses in this and prior cases, correct?

A Yes.

Q Could you please turn to page 9 of your rebuttal testimony.

A I'm there.
Q So this section of your rebuttal testimony, from line 8 to line 25, did you prepare this section or did someone else prepare this testimony for you?
A I prepared this testimony.
Q And I'm assuming that in preparing this section of your rebuttal testimony, you reviewed the exhibits sponsored by Mr. Coppola on the subject matter; is that correct?
A Yes, I did.
Q Now, beginning on line 16 and through line 25, you disagree with Mr. Coppola's assertion in his testimony that the Commission should reject the Company's request to recover forecasted inflationary cost adjustments, correct?
A Yes.
Q And specifically those inflationary cost increases in question would be from the end of the historical year to the end of the projected year; is that correct?
A Yes.
Q I'm wondering if you would please go to Exhibit A-13 C5. I have a copy of that if that would be helpful.
A I do not have a copy of it.
(Document provided to the witness.)
Q Now, Mr. Stanczak, this was -- or this is an exhibit that's sponsored by Theresa Uzenski with her direct

testimony. Are you generally familiar with this exhibit?
A I've seen it before, I'm generally familiar with it.
Q Now, looking at total O&M expenses, which is line, the bottom line, line 12, if I add columns (g) through (i), the amount of forecasted inflation that the Company is asking for in rates in this case is approximately 70 million; is that correct?
A Approximately.
Q Do you have a copy of Mr. Coppola's testimony and exhibits in front of you?
A No, I do not.
Q I'll provide that to you as well.
(Documents provided to the witness.)
Q Can you please turn to Exhibit AG-1.
A I have it.
Q Are you familiar with this exhibit?
A I looked at it, yes.
Q Now, as I understand it, the numbers in this exhibit were sourced from Company work papers, exhibits, and responses to discovery requests; is that correct?
A That appears to be correct.
Q The amounts shown just to the right of the calendar years are the actual O&M expenses incurred by the Company for each year, correct?
A I'm sorry, can you ask that again?

Q Sure. So all the way to the very left column is just the calendar years, and then the next column to the right shows the actual O&M expenses incurred by the Company for each year; is that correct?
A That's what the document says, yes.
Q And as we move further to the right, the next column titled actual percentage change is the percent decline or increase in expenses from the prior year expenses, correct?
A That's what it says. I mean I haven't done the math.
Q The last column in this document represents the 2007 actual O&M expense inflation adjusted over the 2008 to 2017 period, correct?
A Well, I believe that's what's depicted here, but again, I haven't done these calculations.
Q Fair enough. So when looking at this document and the year 2017, which is the last calendar year depicted, the exhibit shows that actual O&M expenses declined by 5.3 percent versus an inflationary increase of 2.1 percent, correct?
A That 2017 decline? I'm not sure I understood the question, I'm sorry.
Q So just simply looking at the last line there, which is the 2017, the exhibit shows that actual O&M expenses declined by 5.3 percent over that period versus an

inflationary increase of 2.1 percent, correct?
A I would agree that the exhibit shows that 2017 O&M was 5.3 percent lower than 2016.
Q Can you please turn to Exhibit AG-3.
A I have it.
Q Are you generally familiar with this exhibit?
A Well, I did look at it, but it's been a little while, but I did look at it when it was first filed.
Q In this exhibit, based on what you remember and what you see here, Mr. Coppola's contention is that if the O&M expenses presented by the Company in Rate Case U-18014 are extended for inflation to the end of 2017, the Company's actual O&M expenses were still $112 million below the inflation adjusted level; is that your general understanding?
A Can I have the question again?
Q Sure. So again, just based on your knowledge from previous review and what's before you in this exhibit, Mr. Coppola's contention is that if the O&M expenses presented by the Company in Rate Case U-18014 are extended for inflation to the end of 2017, the Company's actual O&M expenses were still $112 million below the inflation adjusted level; is that your understanding?
A That's my understanding that that's what is depicted here based on Mr. Coppola's calculation, but I'm not agreeing

that this is an appropriate calculation.
Q And you did not discuss or dispute this calculation or exhibit in your rebuttal testimony, correct?
A That's correct.
Q Can you please go back to page 9 of your rebuttal.
A I'm there.
Q Now, on lines 18 to 20 you state that, although the Company has been able to manage O&M expenses in the past, it can not continue to do so to offset wage growth; is that correct?
A Yes.
MR. KING: I have a document I'm going to circulate marked as AG Exhibit 34.
(Document distributed and marked for identification by the Court Reporter as Exhibit No. AG-34.)
Q (By Mr. King): This is Exhibit A-10 Schedule C5 from Company's Case U-18014, from Ms. Uzenski's rebuttal testimony in that case. Are you generally familiar with this exhibit, Mr. Stanczak?
A I'm suspect that I reviewed it before it was filed back in whenever it was filed, but I can't say that I'm familiar with it, that would probably be an overstatement.
Q So based on this document in this case, again looking at total O&M expense, and this corresponds obviously to the

previous exhibit from Ms. Uzenski that was filed in this case, looking again at total O&M expense and then adding columns (g) through (i) again, in Case No. U-18014 the Company asked for inflation cost adjustments of roughly 76 to 77 million. Do you agree with that?
A Yes, generally, yes.
Q And in that case the Company requested or had total O&M projected expenses in column (l) of more than 1.3 billion, correct?
A That's what the exhibit shows, yes.

MR. KING: Your Honor, at this time I'd like to move for the admission of this exhibit which I have marked as AG Exhibit 34.

JUDGE WALLACE: Any objection to the admission of AG Exhibit 34? (No response.)

Hearing none, the exhibit is admitted. I'm sorry. Mr. King, you said if you add up columns (g), (h), and (i), so 26,6, 31,7, 19,8, that adds up to 76-77 million, roughly?

MR. KING: Correct, roughly in there. I have another document I would like to circulate, and this is a few lines from Ms. Uzenski's rebuttal testimony in Case U-18014.

(Document distributed and marked for identification by the Court Reporter as Exhibit No. AG-35.)

Q (By Mr. King): I mentioned this is just a few pages from Ms. Uzenski's rebuttal testimony in U-18014.
Mr. Stanczak, can you please take a few moments and read the section starting on page 4, line 20, and then through to line 16 on page 5. Let me know when you've had a chance to read that.
A O.K., I've read it.
Q Mr. Stanczak, in this section of testimony, specifically page 5, lines 3 to 9, 3 through 10, Ms. Uzenski stated the same opinion in Case U-18014 as you stated in this case about the Company not being able to keep O&M expenses below inflation; is that correct?
A I don't think she answers or this statement is consistent with what I'm saying in the current case.
Q So you don't think that this section of her testimony is consistent with what you're stating about the difficulty of keeping O&M expenses below inflation in this case?
A Well, generally, yes, but she goes on to talk about reductions in post retirement costs that were used to offset inflation in the past, which is kind of different than my discussion in the current case.
Q But generally you do agree that she has the same opinion about a difficulty in this case of keeping O&M expenses below inflation?
A Generally, yes.

MR. KING: Your Honor, I would -- I'd mark this as Exhibit AG-35, and I would move for the admission of these pages, two pages.

JUDGE WALLACE: Any objection to the admission of Exhibit AG-35? (No response.)

Hearing none, the exhibit is admitted.

MR. KING: I have no further questions for this witness, your Honor.

JUDGE WALLACE: Thank you. O.K. Who's next? Michigan Environmental Council, NRDC, and Sierra Club, right?

MR. BZDOK: Yes. Thank you.

CROSS-EXAMINATION

BY MR. BZDOK:

Q Good morning, Mr. Stanczak.

A Good morning.

Q I have three topics I'd like to discuss with you today: One is looking at a high level at the various rate impacts of the Company's revenue proposals in this case, specifically residential customers; the second is the investment recovery mechanism, or IRM; and the third topic is just to get your thoughts a little further on the issue of performance-based regulation that you address in your rebuttal testimony.

So I'm going to start with your direct

testimony at page 2 where you said -- sorry -- page, yeah, pages 1 and 2. At the very bottom of page 1 and carrying over to page 2 you describe your position as having responsibility for the development and implementation of regulatory strategy and administration for both the electric and gas companies; is that correct?

A Yes.

Q Can you elaborate on what implementation/development of regulatory strategy would entail? So I mean, if you're able to answer based on that, please go ahead.

A Well, as I'm sure you're aware, we make a number of filings throughout the year at the Commission, and obviously those filings can be complex, have a lot of issues, there's a lot of strategy that gets developed prior to filing those proceedings.

Q At a high level, what are -- in your understanding as someone who has responsibility for the development of that regulatory strategy, what are the major objectives or parameters within your purview that the Company attempts to achieve via this process?

A Well, much of that is actually laid out I believe in, on my direct testimony starting on page 4, at the bottom of page 4, line 22, where it addresses the Company's overall objective, talks about, you know, the need for us to provide safe, reliable service, and having rates that are

adequate enough to do that.
Q Thank you, so that's helpful. So safety, reliability, cost effectiveness, and then also delivering reasonable and appropriate compensatory returns to the Company's shareholders and maintaining financial health, that's generally the overview of what the objectives of the strategy are?
A Yes.
Q O.K. So you have, as I understand it, then, within your function, within your responsibility both a set of objectives that are customer-related and then also a set of objectives that are financial- or shareholder-related; is that fair?
A And I would add -- I would agree with those, and I would also add that there's a, you know, a dimension relative to the ability for us to take care and maintain our facilities and be able to run the organization safely and efficiently.
Q Fair enough. In my question, I was assuming that sort of the safety part of that was a customer function, but I suppose there's a component that has to do with the employees as well; is that fair?
A Yes.
Q And then in terms of taking care and maintaining facilities, that is about the maintenance and

reinvestment and such things?
A Yes. And it's really in many respects about ensuring that on an ongoing basis that the organization is able to function the way it needs to.
Q What -- again, my questions for you are high level and general in nature. What -- so within that context, what sort of parameters or metrics or benchmark or information -- benchmark is the wrong word. What parameters or metrics or indicators do you generally keep track of in terms of the Company's progress, success, needs for improvement relative to these strategies?
A That's a pretty broad question. So one thing we look at and we focus on very carefully, as you would expect, is rate impacts to our customers. We also, again as you would expect, we're focused on profitability, return on equity of the utility. And then I think that beyond that, there's a number of measures in terms of operating measures as well as how the Company's doing in terms of reliability and those type of things. So I think there's a whole host of ways that we evaluate how we're doing.
Q And as part of your responsibility, you review or are briefed in some way on how the Company is doing along the lines of these various parameters that you've indicated?
A Yes.
Q Page 6 of your direct testimony, line 9, you state, "The

Company has carefully considered the need for filing this case." And then you say, "While I am aware of the impact that utility rate changes have on our customers, I am similarly aware that our customers expect and deserve safe and reliable service." Do you see that?

A Yes.

Q When -- I'm interested in the first part of that second sentence, while I'm aware of the impact the utility rate changes have on our customers...; can you elaborate what you mean by that in the context of this filing?

A Well, like I said, we do a fair amount of benchmarking in terms of our rates compared to peer utilities, we look at rate changes, our own rate changes over time, so we're quite aware of how our rates have changed and how our rates have changed relative to other peer utilities.

Q Rates or bills or both?

A Well, that's a good question, because in terms of residential customers, we tend to focus on bills, and for commercial and industrial customers, we tend to focus more on rates.

Q While you focus on bills for residential, do you also benchmark rates?

A Yes.

Q Do you have a copy with you of the attachments to the Company's application in this case?

A No, I do not.

MR. BZDOK: May I approach, your Honor?

JUDGE WALLACE: Yes.

(Document distributed.)

MR. KING: Your Honor, may I approach just to remove my materials, gets those out Mr. Stanczak's way?

JUDGE WALLACE: Sure.

MR. BZDOK: We're swarming you. I don't plan to mark this as an exhibit unless somebody insists on that, in which case we have a placeholder to do that. My view is that as part of the Company's filing, that's not necessary, but I'm happy to do it if it is necessary.

Q (By Mr. Bzdok): So what I've handed you, for the record, if you have a minute to look at it, is Attachments 1 through 4 of the Company's application in this case. Whenever today that I hand you anything, it will be with a representation from me that I have not modified something I received from the Company in any way, and so you can rely on that. But subject to that representation, does this appear to you to be the Attachments 1 through 4 to the rate case filing?

A Yes, it does.

Q And if you look at page 4 of the attachments, that's a proposed notice relative to the filing of this case and a

prehearing in this case; is that correct?
A Yes, Attachment 4. I think you said page 4.
Q I apologize. Thank you for the correction. On the first page of Attachment 4, the proposed notice, there is a bullet -- the first bullet indicates that DTE may increase its annual base electric revenues by approximately $328 million above existing base rate levels, along with other requested relief from the Commission; is that correct?
A Yes.
Q And then there's a second bullet that indicates that a typical residential customer's average electric bill may be increased by up to $9.42 per month if the Commission approves the Company's request, right?
A Yes.
Q Would you agree, subject to check, that that 9.42 a month pencils out to about $113 per year?
A Sure, subject to check.
Q And then on Attachment 2 of these applications, that presents a summary of the present proposed revenue by rate schedule; is that correct?
A Yes.
Q And that attachment corresponds to an exhibit by one of the rate design witnesses of the Company; is that correct?

A Yes.

Q O.K. And looking at line 9, column (d), total net increase or decrease for the residential customer class, it pencils out to around $215 million; is that correct?

A Yes.

Q Now, Attachment 1 to the application summarizes the Company's proposed revenue deficiency by major component; is that correct?

A Yes.

Q And it has for the most part a number of positive numbers for projected revenue deficiencies for a number of categories, with two exceptions, those being line 7 and line 9, correct?

A Yes.

Q And I'm not interested particularly in line 7, but I am in line 9. Line 9 is listed as tax reform, and the number there is $196 million negative; is that correct?

A Yes.

Q And as I understand it, what the Company is indicating there is that there is a downward effect on the Company's revenue deficiency associated with the Federal Tax Cuts and Jobs Act; is that correct?

A I'd say it different, that it's a reflection on a reduction in tax expense, but it does impact the deficiency, yes.

Q That's even clearer than my question, so thank you for that. So a reduction in tax expense associated with the TCJA, correct?
A Yes.
Q And as I read -- and without getting into the details of this, as I read Company Witness Sherri Wisniewski's testimony, that number was arrived at based on a somewhat complicated amortization of a deferral; is that more or less correct?
A Well, that's part of it. Part of this is just due to the lower current tax rate as well.
Q In your capacity as Director of Regulatory Strategy and the responsibilities we've discussed, did you have some involvement in the development or implication of the Company's positions relative to the TCJA issues?
A Generally, yes. Sure, yes.
Q So the reason I'm asking is that so, for example, you're familiar with what I mean by the Credit A case?
A Yes.
Q Now, I didn't see you as a witness -- you are very often the Company's primary witness in rate cases, is that correct, or the policy witness?
A I have been the policy witness in recent years, yes.
Q So you were not a witness directly in the TCJA Credit A case, 20105, correct?

A Correct.
Q But I'm taking it from your testimony today that you had some familiarity with, general familiarity with the proceedings in that case; is that correct?
A Yes.
Q And then you also presumably had some general familiarity with the settlement that was reached in that case; is that correct?
A Yes.
Q Just as a very high level so that the record gives us some context, because I know everyone in the room here knows this, but generally speaking, what was the Credit A case about?
A So the Credit A case dealt with the going-forward current reduction in taxes due to the lower corporate tax rates that were implemented January 1 of this year.
Q And did you sign off or approve or otherwise have visibility into the settlement of that case?
A Yes.
Q So what I've projected on the projector --
MR. BZDOK: And may I approach, your Honor?
JUDGE WALLACE: Yes, you may.
Q (By Mr. Bzdok): So what I've projected on the screen and have a copy of for you is something I have marked as

proposed Exhibit MEC-113, which is Attachment B to the Settlement Agreement that DTE filed in that case, which was then subsequently approved by Commission Order dated July 24, 2018.

(Document distributed and marked for identification by the Court Reporter as Exhibit No. MEC-113.)

Q (By Mr. Bzdok): With again the representation that other than putting an exhibit marker on here, I have not modified anything that I've received from the Company. So take a moment and just refamiliarize yourself. Does this appear familiar to you, and subject to my representation to be a comparison of proposed -- a revenue comparison before and after the settlement of the tax Credit A case?

A Can you ask that question again, please?

Q Yeah. I'm just asking if this looks familiar to you from your knowledge of the Credit A case as the Company's revenue comparison by rate schedule associated with that settlement?

A Yes, I think it does.

Q I again want to look specifically at the residential portion. Now, there are two -- so looking at this document generally, there are two different -- there's an attachment. This is Attachment B overall, and then there's an Attachment B.1 and B.2; do you see that at the

top right?
A This appears to be Attachment B.1.
Q Sure. So let me try it again. So on the cover sheet it says Attachment B; do you see that?
A Yes.
Q And then the -- and then there's an Attachment B.1, page 1 of 3, and then after that there's an Attachment B.2, page 1 of 1; are you with me?
A Yes, yes, I'm with you, yeah.
Q O.K. Again, at a high level, the Attachment B.1 deals with present versus proposed revenue related to the Commission's Order in Case 18014, whereas Attachment B.2 deals with present and proposed revenue under the Commission's Order in Case 18255; is that correct?
A Yes.
Q And the --
A I believe that's correct, yes.
Q O.K. Thank you. So my questions for you are just going to be sort of identifying kind of how this pencils out and how it relates to the $196 million in Attachment 1, just so that you know where I'm going with this. On Attachment B.1, line 9, column (d), there's a total net decrease for residential customers in the ballpark of $46 million; do you see that?
A Yes.

Q And then down in line 44, there's a total decrease associated with all classes for the 18014 component of roughly $82 1/2 million, round numbers; do you see that?
A Yes.
Q And then the next two pages are broken out as power supply and distribution revenues, right?
A Yes.
Q And then when you get to line 5 -- to page 5, you got the Attachment B.2, and then you've got another set of total increases or decreases which include for residential customers in line 9 $78.6 million, and for all classes of $156.9 million; do you see that?
A Yes.
Q So based on your understanding and to the extent that you can explain it to me, which of these amounts flowed out of this case and into the $196 million number in Attachment 1 or some portion thereof?
A The way I would recommend you think about this, if you go to B.2 and you look at the line 44, column (d), 156 million, that is what makes up part of what's on our attachments to our application when you look at Attachment 1, line 9, where it has a $196 million reduction, and the balance is what you had talked about earlier, the change in deferred and the amortization of flow through those deferreds.

Q O.K. So again, just looking at residential customers specifically, then, on Attachment B.2, column (d), line 9, total residential of around 78.6 million would be a component of the 196 million tax, that would be the residential component of this portion of that tax reform number of 196, right?
A If by meaning of this portion you mean the go-forward tax break reduction, yes.
Q Sure. And that wasn't very articulate of me, but I was trying to distinguish the impact of the Credit A case from the deferral situation that represented the balance.
A Yes.
Q O.K. To the extent you know and -- or just in your understanding, do you have any sense of how much of that -- the balance would be about $40 million, right, associated with the subject of Witness Wisniewski's testimony?
A By balance, do you mean that the difference between the 156 that's the go-forward amount and the total amount of 196 million?
Q Yep, yep.
A Yes, that's about 40 million.
Q O.K. Do you have any sense of how much of that 40 million would be associated or allocated with regards to residential, the residential customer class as a

whole?
A Sitting here today, I wouldn't know.
Q And again, just in your understanding and at a very general and high level, is it fair to assume that if the residential component of the Attachment B.2 changes was roughly half of the total, that the residential component of the balance would also be roughly half of the total, or is that not a legitimate assumption?
A That's probably an over-simplification, because the repricing of the deferred or the remeasurement of the deferreds is driven kind of by definition by prior deferred taxes, which may or may not line up the same as current revenue in terms of how it's distributed among the classes.
Q Is there a witness who you think would be suited to answer that question?
A I would expect Ms. Wisniewski would be probably able to answer that better than me.
Q As far as your oversight of the team involved in this case, would that also be something Mr. Lacey would have knowledge of?
A He could, yes.
Q So as far as the -- as far as the Attachment B.2 amounts goes, or go, I should say, and looking specifically at the residential, the 78.6 million, what would happen to

that $78.6 million in the absence of the filing of this case?

A I'm not sure I understand what you mean by what would happen.

Q I'm trying to find a way to ask this question that doesn't sound -- I'm trying to find a way to ask this question in a very vanilla manner. But for the filing of this case, that 78.6 million would have -- would flow to residential customers as reductions, based on my understanding of your testimony today; is that a fair characterization?

A This attachment -- or I'm sorry. This Credit A proceeding resulted in a credit on customers' bills that is in place today, and absent filing this rate case, that credit would stay in place indefinitely.

Q One of the -- as I'm understanding your testimony today and the Attachment 1, one of the requests in this case is that that credit would no longer flow to residential customers and instead would be used to fund a portion of the overall revenue deficiency identified in this case; is that correct?

A Well, I would say it differently, and I would say that the credit will be terminated and the impact of the tax change will be reflected in our base rates. It's kind of depicted on Attachment 1.

Q So my interpretation of that answer would lead me to reason as follows: That the total rate impact on residential customers of the Company's test year proposals is the $215 million on Attachment 2, line 9, column (d) plus all or a portion of the 78.6 million in Attachment B.1 specific to residential customers plus some portion of that $40 million balance; is that a fair interpretation?
A I'm sorry, I didn't follow that question. Can I have it again?
Q Do you want to hear it back or do you want me to try to rephrase it?
A Can you rephrase it maybe?
Q I will try to. We've identified in Attachment 2 a total proposed rate impact to residential customers of around $215 million, correct?
A Yes.
Q We've identified a total credit amount in Attachment B.2 specific to residential customers of around $78.6 million; is that correct?
A A credit that's in place today, that's correct.
Q And that credit is a component of the 196 million negative presented in Attachment 1, correct?
A Yes.
Q And so my question is, is it fair to say that as part of

totaling the impact, the impact on residential customers, it would be fair to add the 215 million to the 78.6 million in terms of a total test year impact on residential customers?

A No.

Q Why not?

A Because there will be a further reduction relative to taxes that's the residentials' pro rata share of the incremental 40 million that we talked about earlier relative to the remeasurement of the deferreds and the flow through of that.

Q So it would be, the total amount would be greater than 215 million plus 78.6 million, it would be those two numbers plus some portion of that $40 million balance?

A It would be minus some portion of that $40 million balance.

Q O.K.

JUDGE WALLACE: So just -- I'm not a DTE customer, so I don't know what your bills look like. So with the Credit A, which was basically the rate reduction to reflect the change in the taxes from 34 percent to 21 percent, you didn't re-run the cost of service and do new tariff sheets. So say the rates were 15.1 cents per kilowatt hour and they should have been 14.9, instead of lowering the per kilowatt hour charge, it was implemented

as, actually as a credit of however much the difference between the 34 and the 21 represent, right?

THE WITNESS: Yes.

JUDGE WALLACE: So it's a credit on your bill. Is the Credit B the same way, just -- I mean that one goes away, right, once the money is -- that was the money that was sequestered when the tax law came into effect before the final order in the Credit A, and that's a credit for a certain period of time?

THE WITNESS: Yes.

JUDGE WALLACE: So that both of those line items on a bill, and I think we're not worried about Credit B, go away, and then Credit C, which is the deferred income taxes, that starts to kick in here?

THE WITNESS: Yes. And just for clarification, if I could, Credit B will just expire when it expires, --

JUDGE WALLACE: Correct.

THE WITNESS: -- Credit A terminates when we get an Order, when we get new rates in this proceeding.

JUDGE WALLACE: O.K.

Q (By Mr. Bzdok): So at a high level, 215 million plus 78.6 million minus a portion of the 40 specific to residential customers?

A Yes.

MR. BZDOK: Your Honor, may I approach?

JUDGE WALLACE: You may.

Q (By Mr. Bzdok): So the next document that I want to give you is a discovery response which I've marked as proposed Exhibit MEC-112, it's discovery response MECNRDCSCDE-2.1, it was actually provided by Mr. Bloch in this case.

(Document distributed and marked for identification by the Court Reporter as Exhibit No. MEC-112.)

Q (By Mr. Bzdok): And recognizing that this is Mr. Bloch's exhibit and attachment, my question is really going to be just at a high level if what is presented here is consistent with your knowledge and understanding, and then we can move on from there when Mr. Bloch is on the stand. So here we've asked the Company to provide total net increases requested in this case, including test year and all of the IRM periods for each customer class and rate schedule in dollars and percentage; do you see that?

A Yes.

Q And then on the back there's a spreadsheet printout that looks vaguely similar to one of some of these other ones that we've been looking at that provides customer classes, provides total present revenue, and then both in dollars and percentages provides total 2022 base and IRM increase from present revenue; do you see that?

A Yes.
Q And then in column (c), line 9, there's a total residential increase from the test year plus the IRM of $443 million for -- let me try that again -- $443,458,000; do you see that?
A Yes.
Q And then there's a total for all classes of around $746 million, correct?
A Yes.
Q So if I was looking at totalling an impact on residential customers of the Company's proposals in this case, that would -- the 215 million that we already talked about would be part of this 443.5 million, give or take, right?
A Yes, if I understand what you mean by part of.
Q Not in addition to, but rather a portion thereof?
A Yes.
Q O.K. And then the tax number of $78.6 million minus some component of the 40 million balance would be additional to this 443.5 million, correct?
A Yes.
Q So that's going to land somewhere, depending on where it falls, in the range of around $500 million, would you agree, depending on how much of the 40 million -- there's a range there, but it's going to be somewhere in that neighborhood, plus or minus some amount?

A I'm sorry, what was the -- I'm not sure I understood the question.

Q Sure. So I'm trying to deal with the uncertainty of knowing how much of the $40 million is attributable to the residential customers. So if I take the 443.5 million and I add the 78.6 million, that takes me north of 500 million by -- it puts me around in the 520s, but then if I say, well, it could be as low as 480 if all of the 40 million was attributed to residential, or it could be as high as 520 something if none of it was, so somewhere around the midpoint is in the neighborhood of 500 million; do you follow?

A Yes.

Q O.K. And so that neighborhood of 500 million, plus or minus, would represent the total impact on residential customers of the Company's proposals in this case relative to test year revenue deficiency, the effect of the tax reform item, and the total impact of the IRM, right?

A Can I have the question again?

Q Sure.

MR. BZDOK: Could you read that back, Lori.

(The record was read aloud as follows:

"Q And so that neighborhood of 500 million,

plus or minus, would represent the total impact on residential customers of the Company's proposals in this case relative to test year revenue deficiency, the effect of the tax reform item, and the total impact of the IRM, right?"

A Yes. So I would agree that the 443 million plus the impact of the tax credit elimination reflects the total requested impact on residential customers through 2022.

Q (By Mr. Bzdok): And I don't want to spend a lot of time on this item, but there is also a request by the Company in this case for the creation of a regulatory asset associated with a tree trimming surge; is that right?

A Yes.

Q And that regulatory asset associated with the tree trimming surge is presented by some combination of witnesses, Rivard and Slater; is that right?

A Yes. And Witness Solomon addresses securitization as well.

Q O.K. And that could add some number to these other numbers in the, like single-digit millions through the period between now and 2022; is that right?

A Yes.

Q O.K.

MR. BZDOK: Your Honor, I'm happy to

continue as long as you would like, I'm also going to slightly switch topics and now, so whatever your pleasure is or the witness's is or the court reporter's.

JUDGE WALLACE: About how many more minutes do you think you have?

MR. BZDOK: I do have a while, I'm winding down the first topic, but I have one other which is substantial and one other that's short.

JUDGE WALLACE: All right. We'll continue.

MR. BZDOK: O.K.

JUDGE WALLACE: Mr. Bzdok, don't let me forget, you've got two exhibits hanging out there, so we want to make sure to admit those.

MR. BZDOK: I'm going to -- it would be unorthodox to admit the Bloch exhibit with Mr. Stanczak, so I'm also happy to wait on Mr. Bloch. What we do is totally at your pleasure.

(A discussion was held off the record between Mr. Bzdok and Ms. Hayden.)

MR. BZDOK: Do you want me to move for them now or wait?

JUDGE WALLACE: Oh, do you have -- you can move when you're concluded, when you conclude your cross, I don't know if you have anymore exhibits.

MR. BZDOK: So I do have a few more exhibits, but I'm happy to move for admission of those now.

JUDGE WALLACE: O.K. Can we go ahead and do that, then. Is everybody --

MR. BZDOK: So I'll move at this time for the admission of Exhibits MEC-112 and MEC-113.

JUDGE WALLACE: Any objection? (No response.)

Hearing none, Exhibits MEC-112 and MEC-113 are admitted.

MR. BZDOK: Thank you. So are we continuing for --

JUDGE WALLACE: Yes. Next you're moving into the IRM?

MR. BZDOK: Not yet.

JUDGE WALLACE: Not yet. O.K.

Q (By Mr. Bzdok): Very generally, Mr. Stanczak, do you recall from Case 18255 we had a discussion arising out of your rebuttal testimony as to some proposals that my clients had made through -- relative to providing more energy conservation assistance to payment-troubled low income customers and your rebuttal at a high level that that was an issue that should be addressed in EWR cases; do you recall that discussion generally?

A Generally, yes.
Q And we had some discussion on the stand of whether there was some potential for positive action by the Company on those issues; do you recall that generally?
A Generally.
Q Do you have general understanding from your role as Vice President of Regulatory that there was a settlement related to some of those issues in the Company's EWR cases that did put some additional funds into that need?
A Yes.
Q Do you have any sense from your overview of, and reviewing sort of performance how all of that is going?
A I don't have any direct knowledge of how it's going, no.
Q The numbers involved in that case were high single-digit millions; does that sound ballpark, like what you remember?
A Sounds right, but I don't really remember the detail.
Q O.K. The Company in this case is, again speaking at a general level and understanding you're an overview or lead or policy witness, the Company is proposing in this case to increase the number of low income customers who would be provided with the RIA credit; is that correct?
A Yes.
Q And that's a -- as proposed by the Company, that would be a -- so the Company, as I understand it, at a general

level is making two proposals, correct, (1) is to increase the amount of the credit from $7.50 to $9.00, and (2) is to increase the number of customers who are eligible for the credit from I think 30,000 to 70,000 customers; does that sound right?
A That sounds right.
Q If the $7.50 to $9.00 bump is associated with the or is equal to the Company's proposal to increase the fixed monthly service charge for residential customers; is that correct?
A Yes.
Q So in other words, if the service charge was increased from $7.50 to $9.00, the RIA customer receiving the 7.50 credit would get a bump to $9.00 to essentially cover them for that increase; is that correct?
A Yes.
Q Would those customers get the bump from $7.50 to $9.00 if the Company's proposal to increase the monthly service charge was rejected by the Commission and the service charge remained at $7.50?
A Well, in many respects I think that that's up to the Commission, but it does -- could complicate things in a situation, an unlikely situation where a customer had no usage and their credit was bigger than their service charge.

Q So it might or might not, it's up to the Commission and subject to that complication that you are flagging?
A Yes.
Q Other than the proposed bump in the monthly service charge and the increase in the number of customers eligible for the RIA credit up to 70,000, are there any additional proposals by this -- by the Company in this case to increase the amount of funds relative to low income residential customers that you're aware of?
A No.
Q So if we wanted to total the amount of additional funds being proposed by the Company for residential customers, we would take that 1.50 increment between the 7.50 and the 9.50 [sic], multiply that by 30 or 40,000, I think it's 30,000 -- let me make sure I have the number right. Give me just a second.
So at a high level, is it consistent with your understanding I read from Tamara Johnson's testimony that the current amount of money funded in through the RIA credit is about $3.15 million, and if both of the proposals, the bump in the amount and the increase to 70,000 customers were adopted, the budget would increase to $7.6 million; does that sound generally consistent with your understanding?
A That sounds right.

Q Is there any proposal by the Company in this case to provide any step up in funding for low income customers for the IRM years where there are cost increases to residential customers, including low income customers, as a result of the IRM?
A No.
Q As a part of your -- I want to try to have a general discussion with you in a fairly generic way, and if we need to get into a document, we can, but just generally based on your understanding from your involvement in regulatory strategy and your general review of metrics and parameters related to financial performance, return on equity, and return to shareholders, do you have a general knowledge of -- is it consistent with your understanding that the Company is projecting to investors continued growth in earnings per share?
A That's correct relative to DTE Energy, because DTE Electric shares are not traded publicly.
Q Thank you for that clarification. Is it your general understanding that the Company, that DTE Energy in looking at these issues does break down earnings per share among the various subsidiaries that it owns, including the regulated and the unregulated?
A Can I have the question again?
Q Sure. Is it consistent with your understanding that the

Company in looking at projections for earnings per share breaks down total amounts based on estimates for the Company's various subsidiaries, regulated and unregulated?

A I believe our earnings guidance is typically in millions of dollars by segment.

Q O.K. And the -- is it consistent with your understanding as a general matter that the Company is, that DTE Energy is projecting continued growth in earnings for DTE Electric into 2019?

A Yes.

Q How do you reconcile that fact with the statement on your -- in your direct testimony, page 6, lines 11 to 13, that DTE Electric's current authorized rates are not expected to provide DTE Electric with a reasonable opportunity to earn a fair return on equity beginning in May of 2019?

A First, I think I may have misspoke. I'm not sure that we're projecting higher earnings in '19 than '18, so I do need to clarify that.

Q Sure.

MR. BZDOK: So may I approach, your Honor?

JUDGE WALLACE: Yes, you may.

(Document distributed and marked for identification

by the Court Reporter as Exhibit No. MEC-115.)

Q (By Mr. Bzdok): So I'm going to hand you what I have marked as proposed Exhibit MEC-115, which is a third quarter 2018 earnings conference call presentation by DTE Energy from October 24 of 2018, and I'm going to direct you to page 11 of the presentation, which I also have projected on the screen. And once -- so this is the page that says 2019 operating EPS early outlook grows 6.4 percent from 2018 original guidance, and there is a line at the top for DTE Electric with a 2019 early outlook of 698 million to 712 million. Do you see that?

A Yes.

Q Does that refresh your memory as to what kind of performance, financial performance the Company -- that the Energy Company is projecting for DTE Electric?

A Yes.

Q How does it refresh your memory, or what can you tell me based on this information?

A Yeah. So my confusion was, if you look at DTE Energy in total, the guidance is slightly less for '19 than '18.

Q O.K.

A But I would agree that for DTE Electric, the guidance is slightly higher for '19 than '18, but that was my confusion.

Q O.K. Thank you for clearing that up. So how do I

reconcile this earnings growth with the statement on page 6, lines 11 to 13, that the Company is projecting it won't have a reasonable opportunity to earn a fair return on equity beginning in May 2019?

A Well, the key assumption is that we will get a rate increase from this current rate case and it will have a favorable impact on our ability to achieve these numbers.

Q O.K. This is assuming that some version of the rate increase proposal is adopted?

A Correct.

Q Is it also assuming that some version of the rate increase -- of the IRM proposal is adopted?

A No, because 2019 is not a year where the IRM is in play.

Q So this kind of growth could be seen in 2019 even without the adoption of the IRM?

A Yes.

MR. BZDOK: I'm going to move to admit proposed Exhibit MEC-115.

JUDGE WALLACE: Is there any objection to the admission of Exhibit MEC-115? (No response.)

Hearing none, MEC-115 is admitted.

MR. BZDOK: Thank you. I am going to switch to the IRM next, so whatever your pleasure is.

JUDGE WALLACE: How long do you have on IRM do you think?

MR. BZDOK: I would anticipate finishing with Mr. Stanczak at or before lunch.

JUDGE WALLACE: O.K. Why don't we take ten minutes right now, get some water, and we'll be back here in ten. Thank you all very much. We're off the record.

(At 10:55, there was a ten-minute recess.)

JUDGE WALLACE: Back on the record in Case No. U-20162. Mr. Bzdok, if you'd like to continue, please.

MR. BZDOK: Thank you, your Honor.

Q (By Mr. Bzdok): Mr. Stanczak, at this point I'd like to talk to you a little bit about the IRM and I would orient you initially at page 13 of your direct testimony.

A I'm there.

Q Thank you. So generally starting at page 13 you introduce the Company's proposal for an IRM and you talk about the witnesses who are supporting various components and details related to that IRM. Correct?

A Yes.

Q And then you talk about the rationale for proposing the IRM on page 14, and you have some discussion at lines 2 to lines 16 embedded within that of the potential to defer a rate case if the IRM is approved, generally speaking. Right?

A Yes.
Q And then you qualify that at lines 18 to 23 and indicate that there is no guarantee, however, that if the IRM is approved, that a rate case would be deferred. Correct?
A Yes.
Q And you list various cost measures starting at the bottom of line 14 and moving on to line 15 that could lead the Company to file a rate case before 2022 even if the IRM was approved by the Commission. Correct?
A Yes.
Q And you list incremental capital expenditures, O&M general inflation, other O&M cost increases, reductions in sales, and other unforeseen external events, correct?
A Yes.
Q Now, in terms of your list here, that is not an exclusive or exhaustive list of events or circumstances that could lead the Company to determine it needed to file a rate case prior to 2022. Is that correct?
A Yes.
Q Would one such condition be the amount of overall revenue deficiency that the Commission approved in this case?
A Yes.
Q Could another be the Commission's ultimate decision on ROE in this case?
A Perhaps.

Q So if the Commission's approved return on equity in this case is lower than the Company had sought, that could lead the Company to file a new rate case prior to 2022 even if the Commission approved the IRM, correct?
A Yes.
Q And another possibility would be that the Commission approved an IRM but perhaps not for all of the programs, categories, or amounts that the Company was seeking. Could that also lead the Company to come in with a new rate case sooner than 2022?
A Yes.
Q Now, some of your witnesses, including you a little bit, had some rebuttal testimony relative to some of the Staff's proposed, some of the Staff recommendations to certain kinds of distribution capital expenditures. Question, right? So there are some arguments in this case going on between the Company's witnesses and Staff relative to some proposed distribution capital expenditure amounts, correct?
A Generally, yes, that is correct.
Q And some of those are -- Some of those disputes involve significant amounts of money, would you agree?
A Yes.
Q And so if the Commission was to adopt the Staff's position relative to some of those amounts could that

also lead the Company to come in for a new rate case sooner than 2022?
A Yes, if we were effectively disallowed some capital we've already spent, for example in 2017 or '18, that would create a challenge in terms of staying out.
Q Ultimately, the decision whether to stay out or not is reserved solely to the discretion of the Company, correct?
A Well, I'm not sure I understand the question.
Q There is no -- There is no contract or condition here, DTE and DTE alone will decide whether conditions are such that it can stay out of a rate case until 2022 based on the results of this case or whether it needs to come in sooner?
A Well, the Commission can always initiate a show cause as well.
Q What do you mean by that?
A It's -- the Commission could bring us in effectively for a rate case if they wanted. So you said it's exclusively up to the Company whether or not there is a rate case, and that's where I was kind of not agreeing.
Q No, that's fair. And I understand your point.
So setting aside that show cause circumstance, the Company is reserving to itself the decision based on its view of circumstances and outcomes

when to come back in with the next rate case. Correct?
A Yes. We're not suggesting or proposing that we limit our right to file a subsequent rate case.
Q So the benefit to parties, customers and -- So the benefits to parties and customers of a deferral is intangible and unknown at best. Would you agree?
A I'm sorry. Can I have the question again?
MR. BZDOK: Could you read that back, Marie?
(The record was read aloud by the Court Reporter as follows: "Q So the benefits to parties and customers of a deferral is intangible and unknown at best. Would you agree?")
A No, I would not agree.
Q Nobody knows, as far as customers or parties go, whether DTE will stay out of a rate case and if so for long; would you agree?
A I would agree with that, yes.
JUDGE WALLACE: And that would apply with or without an IRM?
A Yes.
Q (By Mr. Bzdok): I have one specific question for you relative to your testimony about the inflation associated with O&M. And I just need to locate it, so just bear with me a second. O.K.

So page 16 at the top, there's a question, "Specifically how could O&M costs impact the Company's ability to defer filing a rate case?" And the answer is, "Since O&M is not included in the IRM, the Company will be required to absorb any inflation or other cost increases that occur during the pendency of the IRM in order to defer filing a rate case." And then you reference Witness Uzenski's proposed O&M for the projected test year. And then you make a statement. "Therefore, even if the Company experiences general inflation of 2 percent for example, it will have to absorb about $26 million annually." Do you see that?

A Yes.

Q So my question is: What is the significance of that? Are you saying that the Company would expect to absorb that amount of O&M inflation and still stay out, or would not expect to absorb that amount of inflationary O&M and be able to stay out? Or something else?

A So what I'm saying here is, if we, if the IRM was approved as proposed, and we wanted to earn our authorized rate of return through 2022, we would have to somehow absorb the impact of inflation between now and 2022, which would be very challenging. I think there's a scenario where we could do it, but it would be very challenging. And that's the point I'm making here.

Q So it would be a challenge, and sitting here today it's unknown whether at 2 percent inflation the Company would be able to stay out until 2022 even with an approved IRM?
A Correct.
Q O.K. My very last point, which I think is going to be somewhat brief, relates to your rebuttal testimony pages 5 and 6.
A I'm there.
Q Thank you. So page 5, starting line 1, you're asked a question about Staff Witness Laruwe's testimony about performance based regulation or PBR, correct?
A Yes.
Q And then you make a statement that, starting at line 19, that the Staff's report in Case 20147 provides an excellent starting point for further discussion, investigation, and collaboration regarding distribution planning. Then you indicate that implementation of performance based rates and associated measures and metrics would have significant financial, operational, and regulatory implications that are specific and unique to DTE Electric and our customers. Do you see that?
A Yes.
Q Can you elaborate on what you generally were thinking of when you made that statement? I'm not asking you for an exhaustive book-ended list, I'm just kind of looking for

the primary considerations that led you to make that statement.
A Well, one example that comes to mind, if we were going to have measures regarding our generation fleet, our generation fleet is unique and distinct from any other utility's generation fleet. So having a metric, what I would characterize as a generic metric or a series of metrics relative to our generation, to all Michigan utility generation fleets, would probably be counterproductive because none of the fleets are probably identical.
Q So by that are you talking about an emissions based metric?
A Could be. But I had more in mind in terms of performance availability, things like random outage.
Q So there you -- I'm just trying to summarize. I'm not trying to bind you to anything, I'm just trying to make sure I understand the gist of where you're coming from. Am I understanding correctly that there you were referring to the fact that the Company has, owns and operates some relatively older vintage units, and so the Company in a benchmarking process related to outage rates or similar considerations, that the Company feels that would be unfair to benchmark its fleet along those metrics?

A Generally, yes.
Q Any other main or primary considerations that led you to make that statement?
A No. I think you touched on the important one, the age as well. You know, our facilities may have a different vintage than others, which would likely impact performance on various metrics.
Q At a high level, any other general considerations outside of the generation topic that led you to make that statement from lines 21 to 24?
A Well, in terms of age of the facilities, the same goes for distribution facilities.
Q O.K. That's fair. On page 5 as you're continuing your discussion of this topic, starting at line 1 you make the statement, "Although the Company could be supportive of a collaborative for a narrow group of interested stakeholders to review the theoretical concepts of PBR and implications for Michigan, it would be impractical and inefficient to develop the foundations and standards of PBR in such a forum."
So maybe I shouldn't have skipped the last line of your testimony. I just wanted to clarify what you mean by, what is the forum where that would be impractical? The distribution planning dockets?
A I'm rebutting Mr. Laruwe's testimony where he suggests

that PBR should be developed outside the rate case in a transparent way with a number of stakeholders.
Q O.K.
A So I'm referring to what he proposed in his testimony.
Q And two things that you do seem to express some favorable inclination towards are review in the context of a general rate case, and also review in the context of a collaborative for a narrow group of interested stakeholders, correct?
A Yes.
Q So the Company would be supportive of developing PBR over a series of rate cases going forward; is that generally a fair statement?
A Yes.
Q And elaborate on what you mean when you talk about a collaborative for a narrow group of interested stakeholders.
A Well, I think we're open to input from stakeholders, but I think to have a generic collaborative with scores of people, to my experience that hasn't always been very effective for something that probably would have a wide spectrum of ideas relative to these kind of measures.
Q How would one -- So does that mean like the parties to the rate cases or some other -- How would such a group be -- again I'm not trying to bind you with some kind of

commitment by asking you this question, I'm just trying to explore what you mean here. Kind of what would be a way to, in your mind, go about figuring out how to set a group that would participate in a process like that?

A Well, to the point you just made, it could be participants in rate case, some sort of rate case.

MR. BZDOK: A moment in place, your Honor?

JUDGE WALLACE: Off the record.

(Brief pause.)

MR. BZDOK: Thank you, Mr. Stanczak, for your time today. I have no further questions for you.

THE WITNESS: Thank you.

MR. BZDOK: I would just note that we had discussion of Attachments 1 through 4 to the Company's application. I expressed a belief that I did not think I need to mark it as an exhibit, but I would also like to know because we would want to reference that in briefing, that if any party would basically insist or request, that we do mark it as an exhibit for that purpose.

JUDGE WALLACE: Yes. I mean we discussed the application, but technically I don't think it's part of the record unless we have admitted it. So why don't we go ahead and -- let's see. MEC dash --

MR. BZDOK: So I will propose that, so I

will propose to admit it as Exhibit MEC-117. We have handed it out to everybody already, and so I would move for admission of Attachments 1 through 4 to the Company's application as Exhibit MEC-117.

JUDGE WALLACE: Any objection? Hearing none, then Exhibit -- you have a copy of it, correct?

COURT REPORTER: I am looking for one.

(Document was marked for identification by the Court Reporter as Exhibit MEC-117.)

JUDGE WALLACE: So Exhibit MEC-117 is admitted. O.K. Now my list of people, who is next? Mr. Keskey.

MR. BZDOK: Mr. King just asked me if we admitted 112 and 113 and I believe we did.

JUDGE WALLACE: My notes say 112 and 113 were admitted.

MR. BZDOK: I'm just going to note that in an effort to try to streamline things, given the number of witnesses, for several of these witnesses we have marked all our exhibits ahead of time so that, the downside of that is that we'll have some things that are not sequential. The upside is we'll be faster.

JUDGE WALLACE: O.K. Speed is good.

MR. BZDOK: Thank you.

JUDGE WALLACE: Mr. Keskey, are you ready

to proceed?

CROSS-EXAMINATION

BY MR. KESKEY:

Q Good morning, Mr. Stanczak.

A Good morning.

Q The first series of questions I have are related to RCG interests. It's my understanding you filed this rate case on July 6, 2018; is that correct?

A That is correct.

Q And it's my understanding the test year that you're proposing is August 2018 -- excuse me. You're proposing a projected test year of May 1, 2019 through April 30, 2020. Is that correct?

A That is correct.

Q Now, is that a determination that you made in your policy role with the Company?

A Well, I certainly had input to that.

Q Could you describe who else had input and the degree of input?

A Well, that decision was really driven by an assessment that we needed a rate increase in 2019. And given that when the decision was made the last rate case was in play, in many respects it was a function of how quickly we could receive a final order in the, what I'll call the 2017 rate case, U-18255, how quickly we could get that

order implemented, turn around a new case and file a new case, and then when would a likely order come out. And when you did kind of that math with the calendar, we determined we would be able to file on or about July 1, and then ten months later is May of '19. So it was really a combination of a number of us evaluating when we would be in a position to file the case, and then just working the calendar from there.

Q Well, as far as the actual selection of the 12-month period that would comprise the projected test year, was that decision influenced by the amount of the rate increase that you could propose as a result of the selection of that 12-month period?

A No.

Q Did you examine or consider or do you know if anyone else in the Company examined or considered the various rate increase requests that would result from the use of various 12-month periods for a projected test year?

A I don't recall doing that evaluation. Somebody may have, but I don't recall participating in an evaluation like that.

Q Did the legal department have an input on your decision as to what would be considered a valid 12-month projected test year?

MS. HAYDEN: Your Honor, I would object

to that. He's asking for --

JUDGE WALLACE: I'm sorry.

MR. KESKEY: I'll rephrase the question.

JUDGE WALLACE: Please.

Q (By Mr. Keskey): I'm not going to ask you for a legal opinion but I would refer to Section 6a(1), MCL 460.6a(1), which says in a sentence as follows: A utility may use projected costs and revenues for a future consecutive 12-month period in developing its requested rates and charges. Unquote.

Now, in your policy role would you consider that 12-month period as 12 months on and after you filed your rate application? Or what other 12-month period would apply under that statute?

MS. HAYDEN: Again your Honor, object. Essentially he's asking for a legal opinion, interpreting the statute. I don't believe Mr. Stanczak has --

JUDGE WALLACE: Yes. I'm going to sustain that. Mr. Keskey, can you move on? I mean I'm not sure where you're going with this, but yes, I think that you are trying to elicit a legal opinion from Mr. Stanczak, and I think this is something we could deal with in brief.

Q (By Mr. Keskey): O.K. You also indicate in your testimony that to some degree the Company utilized a

historical test year adjusted for known changes. Do you recall that?
A Yes.
Q And could you list the known changes that you considered?
A No, I could not list all the changes that we reflected in the case.
Q Is there somebody else that can, who will be a witness in this case?
A There's probably not one witness that could list each and every change. Ms. Uzenski may be able to address a number of changes. But many of the witnesses, I believe, address various changes from historical test year.
Q Well, let me take it, a few examples, and I'm not trying to repeat what you already talked about, the impacts of the Tax Cut and Jobs Act on your case. Do you recall that this morning?
A Yes.
Q And in answer to some questions from the Administrative Law Judge, I think you indicated that Credit A would terminate with the new rates. Am I correct? Or would you want to expand on that?
A Credit A is proposed to terminate when we receive new rates in this case.
Q It would be rolled in or merged with all the other impacts in this case, is that basically it?

A Technically, no. It will expire when we receive the order in this case.
Q Well, you're not asking for a rate increase that would be based on financial information separate from Credit A, are you?
A I'm sorry. I don't understand the question.
Q Well, I'm trying to be just clear here. Credit A would have to be considered in determining what your net rate increase should be, mainly what the on-going federal tax expense would be at 21 percent instead of 35 percent. Would that be correct?
MS. HAYDEN: Object that this has been asked and answered. I think Mr. Bzdok walked Mr. Stanczak through that whole analysis.
JUDGE WALLACE: I agree. Sustained.
Q (By Mr. Keskey): Now let's look at Credit B. I believe you said it would expire when it expires. Is that correct?
A Yes.
Q And under the Company's proposal, Credit B would expire when?
A Well, we're not proposing anything relative to Credit B in this case, and I can't recall how long that is in place.
Q Now, with respect to Credit C, I'm not sure we got a

clear response from you about Credit C. How does that relate to your rate case?

A Well, if you recall back to the conversation I had with Mr. Bzdok earlier today, Credit C is that incremental $40 million that was -- it's effectively related to that $40 million, that that was beyond Credit A. And it's related to the remeasurement of deferred taxes and amortization relative to that remeasurement. That's really what would have happened and what would have been addressed in a stand alone Credit C proceeding. But it's effectively being handled in this rate case.

Q So would you say that your Credit C would be reflected as of the date any order is issued in this case?

A Credit C -- the impact of what's been referred to as Credit C will be reflected in the final rates in this case.

Q Now, with respect to known changes, you received a rate increase in U-18255 on what date, if you can recall?

A I believe the original order, subject to check, was April 19 of 2018. I'm almost certain it was in April.

Q Now, the Company would still be collecting revenues under that rate order during the test year you use in this case, would it not? Let me rephrase it and say it this way.

The full revenue impact on an annual

basis resulting from that rate increase will not yet be reflected until the 12 months after that rate order. Would that be logical?
A I don't understand the question. I'm sorry.
Q Well, let me ask you it this way. How is the revenues achieved from the last rate order reflected as a known change in your case?
MS. HAYDEN: Your Honor, I'd object to the form of the question. I don't think -- it assumes that the current rates are a change to our proposed rate or --
JUDGE WALLACE: Mr. Keskey, the historical year was 2017, right? And then that's updated. When you say you updated the 2017 historical, you kind of normalized some things for 2017? Or are we talking about going forward from that? Or should we rather take this discussion up with Ms. Uzenski or Mr. Slater?
MR. KESKEY: Well, as I understand it, the historical test year with known changes since would inherently include the impact from the revenue increase resulting from the U-18255 order. And I'm asking him, and I'm asking him for what he knows, how that rate increase or increase in revenues would be reflected in this case. Is it one of the known changes?

A I would say technically it's not a known change because when we calculate our deficiency, it's based on present revenue, which reflects the result of Case U-18255. So from my perspective, revenue that's produced given those rates are what they are.

Q (By Mr. Keskey): Well, the revenue from those rates resulting from U-18255 for the historical test year would not be reflected in the historical test year of 2017 but they would impact your revenues on and after April 2018 when the order was issued. So is the full impact of that rate order reflected in the revenues as a known change, if you know?

A The full impact of the U-18255 is reflected in our reflection of present revenue in the current case.

Q Is there another witness that can provide more information on that?

A Possibly Mr. Bloch in terms of describing present versus proposed revenue.

Q Now, is the refund that the Company made or has proposed resulting from the self-implementation rate increase in U-18255, and which is the subject of I believe your docket 20258, is that reflected as a known change?

A That's really not reflected in this proceeding at all.

Q Now, turning to the subject of the IRM, did you have a role in selecting the projections for the IRM going

through 2022? Did you have a role in that decision?
A I'm sorry. I'm not sure I understand the question.
Q Well, the IRM proposal that you have that would be for the years going out to 2022?
A I was very heavily involved in the development of our recommended mechanism.
Q And do you know if any analysis in that mechanism referred to the statutory limitations as to what a projected test year is?
A No.
Q Now let me turn to the subject of tree trimming and securitization. Did you have a role in determining the policy that should be included in this case relative to tree trimming and securitization?
A Yes.
Q Now your testimony and that of Heather Rivard discusses this issue. First of all, you're not actually proposing or filing an actual securitization case within this case, are you?
A That is correct.
Q And I believe somewhere it was indicated that you would propose securitization at about the time that you invested $100 million in the program over and above base rates; is that right?
A Witness Solomon addresses the timing of securitization,

and what he, I believe he says, we will likely do a first securitization after we incur a hundred million dollars of costs, and then we will likely do subsequent securitizations every other year until the surge is completed.
Q Now, because we don't know what the interests are and we don't know what they will be and we don't know the financial comparisons between securitizing or not securitizing, there's no way to determine in this case whether there would be any savings from securitization. Would that be correct?
A No, I don't think I would agree with that.
Q Well, the securitization process does involve overhead or issuance of bonds, administration, commission fees, a whole host of expenses that's over and above the actual program expenses. Is that correct?
A I don't know what you mean by program expenses.
Q Actual dollars invested in tree trimming.
A There are additional fees that would be incurred. I would agree with that.
Q So would determining savings from securitization have to involve the comparison of the interest costs of the securitization bonds compared to alternative utility financing methods, whether it be short-term debt, long-term debt, or other costs?

A I think Mr. Solomon would be better prepared to answer those questions.

Q Now, is there any reason why if the Commission were to grant the Company its requested level of tree trimming expenses in the projected test year or the historical test year, that the expansion and faster accomplishment of tree trimming be accomplished just as easily as if you had securitization?

A I don't understand the question.

Q Have past Commission orders hampered the Company's tree trimming operation?

A Past Commission orders have not granted or approved the level of tree trimming expense that the Company has requested, which resulted in less tree trimming occurring than we proposed.

Q Well, tree trimming is one of many different expenses that make up operation and maintenance expenses. Is that correct?

A Yes.

Q Do you have any example of where the Commission's grant of tree trimming expenses in a past case has resulted in the Company not earning its authorized rate of return on common equity?

A Again I'm not sure I understand the question.

Q Well, have you or any witness undertaken an analysis of

the past Commission orders, what they granted you for tree trimming compared to what the Company requested?
A Yes.
Q And what exhibit would that be, if you know?
A I'm sorry. I didn't hear you ask whether or not we had an --
Q What exhibit or witness would handle that comparison?
A Ms. Rivard would probably be able to talk about that difference. I'm not sure we have an exhibit, however, relative to that.
Q Now, if the Commission in this order were to grant the Company's full request for tree trimming for the test year, that would not hamper the Company's tree trimming operations for the test year, would it?
A I'm not sure what you mean by hamper. But if the Commission approved the requested amount, that would be very helpful in us conducting the tree trimming that we think is appropriate.
Q And if the Commission grants you what you request for tree trimming for the test year, that doesn't necessarily require the management to actually spend up to that level, does it?
A No.
Q Is the Company willing to consider a two-way tracker in which the Commission might grant you your request for

tree trimming, and if you under-spend, that you accumulate that for the next year or refund it to customers?

A I think that's something we'd be interested in evaluating.

Q If the Commission were to grant you in this rate order and in future rate orders for a five year-period what you request for tree trimming, coupled with a two-way tracker, would that give the Company enough certainty to undertake a robust tree trimming operation such that it would not need to propose securitization?

MS. HAYDEN: Your Honor, I think the question called for quite a bit of speculation.

JUDGE WALLACE: I agree.

MR. KESKEY: Your Honor, I think it's a policy evaluation here on a major issue. He's a policy witness. If he can't answer, he can explain why not or he can condition his answer.

JUDGE WALLACE: All right. Do the best you can.

A Well, I think the things you suggest are all mechanisms that I think would be considered, but sitting here on the witness stand today, I certainly could not commit the Company without a more thorough understanding of what's being proposed. So again I think it's something that

would be worthwhile evaluating, but I certainly here today can't commit to anything.

Q (By Mr. Keskey): Well, would you agree from a policy standpoint that an alternative to securitization would be if the Commission adopts a robust budget for tree trimming along with some kind of protective two-way tracker such that you have certainty so you can plan on a short-term and a long-term tree trimming program?

MS. HAYDEN: Objection.

JUDGE WALLACE: Mr. Stanczak has already indicated that this is something that the Company would consider. But has a tree trimming tracker been proposed by any witness in this case? I don't think so. So at this point I think you're kind of putting him on the spot, don't you think?

MR. KESKEY: Well, I think that's the purpose of cross-examination, for one thing. And secondly, the idea of a tracker is mentioned in the testimony of, I believe, Witness Rivard. Although it's not defined, it's what they mean. So I'm just asking a policy question.

JUDGE WALLACE: Can you answer the question?

A Well, this -- what I will answer is, anything that has us recovering the cost of an increase in tree trimming in a

short period of time will have a more pronounced impact on rates than what we're proposing with deferral and securitization. Because our proposal spreads out the recovery of the surge over a much longer period of time than just recovering it in O&M the year that it's incurred.

Q (By Mr. Keskey): However, you can't establish a savings because there is no proper analysis under a securitization statute to determine whether savings would or would not result, right?

A No. I disagree.

Q You have not filed a securitization case on this, have you?

A No, we have not.

Q So if you carve out tree trimming as one expense from all the other expenses that you incur, the impact of securitization is to take that off-line from overall operation and maintenance analysis regardless whether you earn in excess of your common equity return. Would that be correct?

A I'm not sure I understand that question.

Q Let's take a hypothetical where when you include your tree trimming expenses along with all of your other expenses, and you nevertheless earn in excess of your authorized common equity return, then the Company has not

been shortchanged by some variance between a Commission order on tree trimming expense and what the Company requests. Would that be logical?

MS. HAYDEN: Objection. That calls for speculation. That's assuming facts that aren't in evidence.

MR. KESKEY: I'm simply asking, your Honor, for a concept. This witness is talking about securitization and tree trimming, and why take this one element of expense out of perhaps hundreds of elements of expense and separate it into securitization in an example where the Company is overall earning in excess of its authorized return, common equity return.

MS. HAYDEN: Your Honor, we have witnesses that discuss the tree trimming expense and the securitization methods in their direct and their rebuttal testimony. So Mr. Keskey's questions are assuming that none of this has been discussed elsewhere, and he's asking hypotheticals about situations that aren't accurate.

JUDGE WALLACE: I agree. I agree. Perhaps some of these questions would be more appropriate for other witnesses. And I'm still not clear on what your question is with respect to securitization. It appears that Mr. Stanczak did explain that this tree

trimming expense as the Company has proposed is quite large, and that's why they're proposing the securitization as one option for addressing that.

So if you want to continue, please do.

MR. KESKEY: O.K., your Honor.

Q (By Mr. Keskey): With respect to your tree trimming proposal overall, you are proposing that any expenditure by the Company over what is reflected in rates in the rate order would be established as a regulatory asset. Is that right?

A Well, it would be deferred. We are proposing that it be deferred. And then when the program is -- at various times during the pendency of the program we would securitize that deferred balance.

Q And so that deferred balance would be a regulatory asset?

A Well, I'm not sure what the right accounting terms are. Ms. Uzenski could maybe help you with that.

Q And to your knowledge, would a regulatory asset also incorporate a rate of return on that regulatory asset or that deferred balance?

A Well, it certainly would not once it's securitized.

Q But between the deferred and while it's being accumulated and the securitization, it would incur an interest cost, would it not?

A It would be -- my expectation is it would be reflected in

rate base, yes.
Q And the overall rate of return?
A Yes.
Q Now I'd like to turn to some questions on behalf of the Great Lakes Renewable Energy Association.
I note in your testimony and rebuttal testimony that you don't mention anything about the distributive generation proposal or tariffs. Is that right?
A Yes.
Q So you're not providing any input on policy as to those issues?
A Correct.
Q Did you play a role in inputting on the testimony of other witnesses on that issue?
A Well, to the extent I reviewed everybody's testimony, yes.
Q And what was your input relative to net metering?
A Well, I reviewed our proposal and I had input to our proposed distributive generation tariff.
Q Now your testimony also includes no analysis or discussion of customer owned solar and co-customer owned solar, correct?
A Yes.
Q Same answer with respect to community solar?

A Yes.
Q How about utility owned solar?
A I do not cover utility owned solar.
Q Now, what is the relationship of the Company's case and the Company's renewable energy plan case in U-18232?
A I'm not sure what you mean by relationship.
Q Is the Company's -- are the Company's proposals in the renewable energy plan case, U-18232, considered in the analysis in this case?
A No. Our renewable program is a discrete program with discrete ratemaking not covered in this case.
Q So any revenue or expense impacts from the renewable energy plan case are not considered in this case?
A Yes.
Q They are considered or not?
A They are not considered.
Q How has the Company considered PURPA contracts or pending PURPA transactions in this case?

MS. HAYDEN: I'd object to the relevance of these questions. Again if you read the Company's testimony and exhibits, they are what we proposed. And I'm not sure why we're talking about the REP plan and PURPA currently when they are not involved in this case.

JUDGE WALLACE: Yes. Sustained. It, the cost recovery for the Company's renewable energy plan

flows through PSCR which we're not dealing with here, and transfer price PURPA contracts or PPAs for the most part, so that also is addressed in the PSCR. And Mr. Stanczak has already indicated that -- well, we know from his direct testimony there is nothing in there about it. So there is not much that he can respond to with respect to cross. And there may be again better witnesses to discuss rider 18 and the net metering, changes to net metering than Mr. Stanczak. So go ahead, Mr. Keskey.

Q (By Mr. Keskey): Would the ALJ's summary just now need any supplementation by you as to where and how the Company may be considering PURPA projects which are waiting in the queue, let's say, for contracting with DTE Electric?

A I'm not sure I understand the question.

JUDGE WALLACE: I mean there's also an on-going PURPA avoided cost case. Is that 18091? Again that's kind of its own case. So you know, there's that. I don't know whether you can think of anything else.

A I would agree with your Honor. PURPA issues are really not an issue in this case.

Q (By Mr. Keskey): And so they wouldn't be considered relative to your projections of operation costs, PSCR costs or capital costs or any other factor in this case?

MS. HAYDEN: Object to the form of the

question. If there's something specific that Mr. Keskey has a question on, he can see if he can answer it. But these are very open-ended questions.

JUDGE WALLACE: Mr. Keskey, do you have something specific? Interconnection costs, something like that?

MR. KESKEY: Well, I couldn't hear the objection, your Honor. So I thought the witness was trying to answer, but if he doesn't know, that's fine. I mean --

A There could be interconnection costs forecasted in our distribution costs. There could be other very minor costs relative to PURPA. But in terms of PURPA contracts and the like, that's not an issue in this case.

Q Now, have you been involved in working on or inputting on DTE's integrated resource plan that has to be filed in the future?

MS. HAYDEN: Again, objection. We have a filing due in March, and there will be plenty of questions asked at that time. I don't know that it's relevant to this case.

MR. KESKEY: Well, your Honor, it's a foundational question to my next question.

JUDGE WALLACE: I'll allow it.

A Can I have the question again?

Q (By Mr. Keskey): Have you been involved in inputting into the formulation of the Company's integrated resource plan that's going to be filed in approximately March of 2019?

A Well, I have certainly been involved. I think input is -- I'm not sure I would characterize my involvement would be like inputting information into the, into the filing that we're going to make in March. But I certainly have been involved in the work that's being done.

Q Do you know if there are any impacts on this rate case that would incorporate aspects of the IRP planning?

MS. HAYDEN: Object to relevance.

JUDGE WALLACE: Well, the Company is preparing an integrated resource plan. That's not free. So are the costs of preparing the IRP included somewhere in this case that you know of?

A I'm not aware, but other witnesses may be aware.

Q (By Mr. Keskey): Do you have a recommendation on which witnesses?

A Maybe Ms. Dimitry.

MR. KESKEY: I have no other questions, your Honor.

JUDGE WALLACE: One cough drop worth of cross? Or do you want to wait till after lunch?

MR. SINGH: I prefer to wait until after, your Honor.

JUDGE WALLACE: All right. Then we will pick up with -- what is it, 12:20? Say 1:30, 1:45? How about 1:45 we'll be back. Then we'll finish up with Mr. Stanczak, and then Ms. Rivard is next.

(At 12:22 p.m., the hearing recessed for lunch.)

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Lansing, Michigan
Wednesday, December 12, 2018
At 1:45 p.m.

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(Hearing resumes following the lunch recess.)

JUDGE WALLACE: All right. We are back on the record in Case No. 20162, DTE Electric Company rate case. Mr. Stanczak is on the stand, and Staff has some questions on cross.

MR. SINGH: We do.

JUDGE WALLACE: You may proceed.

MR. SINGH: Thank you, your Honor.

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D O N M. S T A N C Z A K

resumed the stand, and having been previously sworn, testified further as follows:

CROSS-EXAMINATION

BY MR. SINGH:

Q Mr. Stanczak, good afternoon.
A Good afternoon.
Q My questions will be brief. Now, I believe earlier this morning it was stated that you are currently the V.P., Vice President of Regulatory Affairs for the Company; is that correct?
A That's correct.

Q O.K. And my understanding reading your testimony, that's since 2013; is that right?
A Yes.
Q O.K. Do you recall what your position or title was around 2011?
A I would have been Director of Regulatory Affairs for DTE.
Q O.K. So are you familiar with allowance for funds used during construction, the AFUDC?
A Yes, I'm familiar with, yes, that concept.
Q O.K. Is it possible, could you describe in a general sense what is AFUDC?
A Sure. Well, AFUDC stands for allowance for funds used during construction, and what it is, it's a regulatory ratemaking methodology that allows utilities to book return on certain large capital projects while they're under construction.
Q O.K. Now, can you describe what DTE's position would be in this case regarding AFUDC?
A Well, just generally what happens is that the earnings portion of -- let me back up.
The AFUDC, the capital that's in question shows up in our rate base, and then there's what's called an AFUDC offset reverses the income impact of AFUDC, so the idea is that we don't get to recover return twice on these projects.

Q Thank you. So in the recent past, has it been DTE's position that ratepayers would not pay for project financing until that project was in service?
A Well, I would agree that's the general ratemaking methodology that's been employed for our ratemaking.
Q O.K. So essentially, then, your position that you're stating is that investors would finance construction of capital costs while ratepayers would pay later once there was a Commission Order reflecting those project costs in rate base; is that correct?
A Well, I just want to be clear that investors would supply the funds, but, in the end, our customers would pay for the carrying costs during the construction period, but it would happen after, the actual cash would be received from customers after the project is put in service and put into rates.
Q Thank you for that answer. So at this point, does DTE's current filing in this electric rate case change any methodology that DTE has employed in the past?
A Witness Uzenski would probably be better addressing the details of what we've proposed in the past and what's in this case.
Q O.K. Well, to your knowledge, as the policy witness, are you aware of any policy change regarding AFUDC?
A Well, I know that it's my belief, but again, Witness

Uzenski would probably know for sure, that in the past the AFUDC offset that I described earlier was just based on the historical test year, some past amount, and now we're using a specific calculation I believe. That's my understanding. Now, I can't tell you if this is the first case or the third case that we've made that change, but I do know there's been a change.

Q Thank you for that answer. We have no further questions. Thank you, Mr. Stanczak.

A Thank you.

JUDGE WALLACE: I have just one quick question. Case No. U-18150 is the Company's electric depreciation case, correct?

THE WITNESS: Yes.

JUDGE WALLACE: And there's been a Settlement Agreement filed that case?

THE WITNESS: The Order was actually issued last week.

JUDGE WALLACE: Oh, the Order has been issued.

THE WITNESS: Correct.

JUDGE WALLACE: O.K. So how -- are you going to treat that in revised testimony, or is it just going to be addressed in the brief? I mean this is a number that just drops into this case, correct?

THE WITNESS: Correct. So what's happened in the past is whatever rate base is approved, whatever gross plant is approved in the case, then the rates will just be applied, and that will, you know, be a component of the rate relief. And it's really not that significant of an issue because virtually in every case there's some minor adjustment at least to capital, so depreciation has to be recalculated anyway.

JUDGE WALLACE: All right. O.K. But we'll use that new rate that's been --

THE WITNESS: Correct.

JUDGE WALLACE: -- approved in U-18150?

THE WITNESS: Yes.

JUDGE WALLACE: O.K. All right. Ms. Hayden, do you have any redirect?

MS. HAYDEN: I do, your Honor, just short, just a few questions.

JUDGE WALLACE: O.K.

REDIRECT EXAMINATION

BY MS. HAYDEN:

Q Mr. Stanczak, do you have the Attorney General's Exhibit AG-34 with you?

A Yes, I do.

Q Do you recall discussing this exhibit with Mr. King?

A Yes.

Q O.K. I believe he asked you about the projected adjustments requested by the Company for inflation, and those are reflected in columns (g), (h), and (i), correct?
A Correct.
Q And I believe it was your testimony that the summation of those columns equaled something in the range of $76 million; is that accurate?
A Yes.
Q Do you recall if the Commission granted the Company's request as outlined on this exhibit?
A Well, certainly not in total, no, the Commission did not.
Q Do you know in particular if they granted the inflation amounts requested in those columns (g), (h), and (i)? I'm sorry. Yes, (g), (h), and (i).
A No. The amount awarded was smaller, and the overall amount awarded for the rate increase was significantly smaller than requested.
Q O.K. Would the Company have spent differently had the Commission granted that request?
A My expectation is that if the Company would have received the rate increase or a rate increase near what we had requested, we probably would have spent much closer to what we had forecasted in this exhibit.
MS. HAYDEN: I have no more questions,

your Honor.

JUDGE WALLACE: All right. Mr. Stanczak, you're excused, and we will move on. Thank you very much.

THE WITNESS: Thank you.

(The witness was excused.)

- - -

JUDGE WALLACE: O.K. We're moving on. Our next witness is Ms. Rivard, correct?

MS. HAYDEN: That's correct, your Honor.

JUDGE WALLACE: Before we call her up, who has cross for Ms. Rivard? (Show of hands.) Mr. King, Mr. Keskey.

MR. SINGH: Nothing from Staff.

MR. BZDOK: We do not, Judge.

JUDGE WALLACE: O.K. All right. Ms. Rivard.

- - -

(Documents marked for identification by the Court Reporter as Exhibit Nos. A-13 and A-22.)

- - -

H E A T H E R D. R I V A R D

was called as a witness on behalf of DTE Electric Company and, having been duly sworn to testify the truth, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. HAYDEN:

Q Good afternoon.

A Good afternoon.

Q Would you please state your full name and business address for the record?

A Heather Rivard, One Energy Plaza, Detroit, Michigan 48226.

Q Did you file with the Commission a document titled the Qualifications and Direct Testimony of Heather D. Rivard, consisting of a cover page and 15 pages of questions and answers?

A Yes, I did.

Q Do you have any changes you would like to make to your direct testimony today?

A Yes, I do.

Q And walk us through those changes.

A Yes. Specifically on page 22 of my direct testimony, on line 19 it talks, mentions a "$46 million favorable" -- on line 19, it mentions "$46 million" of favorable NPV to customers, and that number is revised to "$66 million". And that is as a result of a discovery question asked by the Attorney General that pointed out an error in one of my exhibits.

Q Ms. Rivard, is that 66 or 67?

A 66. Let me check the exhibit, make sure I'm not wrong, the revised exhibit. It is $66.6 million.
Q For rounding purposes, 67?
A Yes.
Q Are you sponsoring any exhibits with your direct testimony in this case?
A Yes. The Revised Exhibit A-22.
Q Is that Exhibit A-22 Schedule L1, two pages of Schedule L1?
A Yes.
Q And then Exhibit A-13 Schedule C5.6?
A Correct.
Q Were the exhibits prepared by you or at your direction?
A Prepared at my direction.
Q Do you have any changes to make to either of those exhibits?
A Yes. Exhibit A-22 Schedule L1, page 1, rows 25 and 30, are what the Attorney General pointed out in his discovery questions where there was an error in the summation of those columns.
Q What should those numbers read? Can you tell us what they used to read and what they currently read?
A There are 20 years' worth of numbers, do you want me to read all of them?
Q So the summation of the numbers is changed from --

A Yeah, for all the columns on pages 1 and 2.
JUDGE WALLACE: And that's reflected in your revised exhibit?
THE WITNESS: Yes, which I think we are filing today as part of the testimony.
JUDGE WALLACE: All right.
Q (By Ms. Hayden): Correct. So just so we're clear, that's lines -- every column under lines -- what line, I'm sorry?
A What the AG pointed out in his discovery question, for example, is on line 25, which is meant to be a summation of 22, 23, and 24.
Q O.K.
A Line 22 was omitted from the summation in all columns. And in addition, line 27 was omitted in the summation in line 30 in all columns.
Q O.K. So lines 30 and lines 25 are revised, correct --
A Correct.
Q -- to reflect that summation?
A Correct.
Q O.K. Any other changes you want to make?
A No.
Q Did you also cause to be filed with the Commission a document titled Rebuttal Testimony of Heather D. Rivard, consisting of a cover sheet and eight pages of questions

and answers?
A Yes, I did.
Q Do you have any changes you wish to make to your rebuttal testimony?
A No, I do not.
Q Is that the rebuttal testimony that you are adopting today?
A Yes.
Q And are you sponsoring any exhibits with your rebuttal testimony today?
A No, I'm not.

MS. HAYDEN: Your Honor, DTE Electric moves to bind into the record the Revised Qualifications and Direct Testimony, the revised -- excuse me -- Rebuttal Testimony of Heather D. Rivard, and for the admission at the end of cross of Revised Exhibit A-22 Schedule L1, and Exhibit A-13 Schedule C5.6.

JUDGE WALLACE: Is there any objection to binding in the testimony, revised testimony and rebuttal testimony, as well as Exhibit A-13 and Revised Exhibit A-22 Schedule L1 into the record? (No response.)

Hearing none, the testimony and Exhibits A-13, A-22, and A-22 are Revised A-22, are admitted in the record.

(Testimony bound in.)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

REVISED DIRECT TESTIMONY

OF

HEATHER D. RIVARD

DTE ELECTRIC COMPANY
QUALIFICATIONS OF HEATHER D. RIVARD

Line
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Q. What is your name, business address and by whom are you employed?

A. Heather D. Rivard, Senior Vice President of Distribution Operations, One Energy Plaza, Detroit, Michigan, 48226. I am employed by DTE Energy Corporate Services, LLC, a subsidiary of DTE Energy.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q. What is your educational background?

A. I graduated from the University of Michigan with a Bachelor of Science in Engineering in 1992. I also earned a Master's Degree in Business Administration from the University of Michigan in 2004.

Q. What is your work experience?

A. I began my career with ANSER Corporation and worked there from 1992-1993. I have been employed by DTE Electric since 1993 and was first assigned to the Customer Information Technology group where I worked on the prioritization and review processes for information technology projects. Over the years, I held a number of positions with increasing leadership responsibilities in areas that include: Customer Marketing, a DTE Energy start-up subsidiary, Customer Service, DTE Electric President's Staff organization, DTE Electric's Lapeer and Pontiac Service Centers, Customer Billing, and Enterprise Performance Management.

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In 2006, I was promoted to Director – Electric Service Operations where I was responsible for the operation of thirteen service centers leading over 1,000 employees performing maintenance, operations, and construction on DTE Electric's electrical distribution system.

In 2011, I began working for DTE Energy's Corporate Services organization as the Executive Director, and was promoted to Vice President of Corporate Services in 2014. In these roles, I was responsible for DTE Energy's procurement, warehousing, fleet, facilities, and real estate operations.

Prior to my current position, I served as the Vice President of Electric Distribution from 2015 to 2016. In this role, I was responsible for overseeing the Company's electrical system construction, including new customer connections, distribution reliability planning and construction, distribution contract management, tree trimming, and emergency responsiveness.

Q. What are your current job responsibilities?

A. Currently, I am the Senior Vice President of Electric Distribution. In this role, I am responsible for the delivery of electricity to the homes and businesses of DTE Electric's customers. This includes tree trimming, engineering, system planning, construction, system operations, substation operations, outage restoration, field and meter services, and system maintenance activities.

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Q. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A. Yes. I sponsored testimony in the following cases:

U-16246	DTE Electric's 2009 Restoration Expense Tracking Mechanism
U-16578	DTE Electric's 2010 Restoration Expense Tracking Mechanism and Line Clearance Expense Report

DTE ELECTRIC COMPANY
REVISED DIRECT TESTIMONY OF HEATHER D. RIVARD

Line
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Q. What is the purpose of your testimony?

A. The purpose of my testimony is to:

- Discuss the importance of DTE Electric's vegetation management ("Tree Trimming") program;
- Support the historical Operations and Maintenance (O&M) expenses related to tree trimming efforts for 2017 and the projected O&M expenses for May 1, 2019 to April 30, 2020;
- Provide details related to the Company's development of a Tree Trimming program structure that will deliver on the reliability goals established in the Company's Five-Year Investment and Maintenance Plan ("Five-Year Plan");
- Describe the customer benefits of the proposed expansion in the Company's Tree Trimming Program

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am supporting the following exhibits:

Exhibit	Schedule	Description
A-13	C5.6	Projected Operation and Maintenance Expenses – Distribution Expenses
A-22	L1**Revised**	Projected Value of Tree Trimming Surge Program

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Outline of Testimony

Q. How is your testimony organized?

A. My testimony is organized as follows:

- Recent progress of the Company's Tree Trim program
- Vision for Tree Trimming
- Surge proposal description
- Benefits of the Surge proposal
- Funding required
- Funding mechanics
- Resourcing the Surge
- Herbicide program
- Measuring progress
- Conclusion

Recent Progress of the Company's Tree Trim program

Q. What is the Company's Tree Trimming program?

A. The Company has an ongoing Tree Trimming program to address interference between vegetation and overhead electric distribution facilities. The objectives of the program are to reduce tree-related safety hazards and to reduce the volume of tree-related trouble cases. The Company's Tree Trimming program, which is based on industry best practices and the Company's experience, is known as the Enhanced Tree Trimming Program ("ETTP"). The ETTP was described in detail in testimony in the Company's last two rate cases: Case No. U-18014 and Case No. U-18255.

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Q. How does the ETTP define tree work to be performed based on circuit zones?

A. In the right-of-way of all Zones, the Company attempts to remove all small trees and larger trees that pose an unacceptable risk to the electrical system. Additionally, the Company attempts to mitigate all hazard trees (trees outside the right of way that are dead, diseased, or dying and threaten to interrupt service to customers).

Specifically, in Zone 1, the portion of the circuit from the substation to the first protective device or drop down, the Company removes all branches overhanging the conductors. In Zone 2, the portion of the circuit from the first protective device or drop down to the fused lateral, the Company removes all softwood branches overhanging the conductors and hardwood branches overhanging the conductors at less than a forty-five-degree angle. In Zone 3, the fused laterals, the Company removes all softwood and hardwood branches overhanging the conductors at less than a forty-five-degree angle.

Q. What were the results of the Tree Trimming program in 2017?

A. The 2017 results will be described in terms of miles trimmed, cost to achieve, reliability impact, and customer satisfaction.

(i) Annual Plan Miles Completed: The Company trimmed 3,601 line miles on 305 separate circuits in 2017 compared to a plan of 3,618 miles.

(ii) Costs to Achieve: DTE Electric spent $84.3 million on the tree trimming program in 2017. This equates to $9.1 million more than the $75.2 million of funding approved in MPSC Case No. U-18014, which was the Company's rate case with a projected test year of August 1, 2016 through July 31, 2017.

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(iii) Reliability Impact: Circuits trimmed as part of the ETTP had an average annual reduction of approximately 50 percent in the number of tree-related customer interruptions and an average annual reduction of approximately 80 percent in the number of customer minutes of interruption in the year following trimming.

(iv) Customer Satisfaction: According to J.D. Power, Power Quality and Reliability (PQR) is the highest driver in affecting overall customer satisfaction. Both the Residential Electric and Business Electric PQR scores for the Company improved from 2016 to 2017 by approximately 3%-4%. The tree trimming program is the program with the biggest impact on system reliability. Another important measure of customer satisfaction is the number of MPSC complaints filed each year related to the Company's tree trimming work. Although the complaints for tree-related service issues increased slightly in 2017 (35 complaints vs. a prior five-year average of 31), approximately 70% of the complaints were driven by customers asking for tree trimming, with the next highest complaint pertaining to debris removal. The complaints have not been driven by customer concerns regarding the tree trimming work conducted on their properties; rather, they demonstrate customers' support for tree trimming and its positive impacts on reliability and costs.

Q. How many miles does the Company anticipate trimming in 2018?

A. The Company plans to trim 3,978 miles in 2018. This is 377 more miles than the 3,601 that were trimmed in 2017.

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	Annual Plan Miles Completed / Planned	Percent of Distribution System
2017 Actual	3,601	12%
2018 Plan	3,978	13%

TABLE 1 – Tree Trimming Mileage

Q. Does the Company expect to achieve the 2018 target?

A. Yes. The Company has prioritized a mix of circuits that will encompass the 3,978-mile target.

Q. How are circuits prioritized for trimming?

A. The Company prioritizes circuits for trimming based on reliability impacts, wire down reductions, and the number of years that have passed since the last trim. Resource balancing across the service territory is also considered to ensure resources are available to respond to unplanned events in a timely manner.

Q. What has been the reduction in events on circuits trimmed to the ETTP?

A. The actual reduction compared to the three-year average preceding trimming, and excluding the historically unprecedented March 8, 2017 wind storm, is approximately 47%, as depicted in Table 2.

	Number of Circuits Trimmed	% Event Reduction in Year after Trimming
ETTP	322	47%
Clearance Circle	2,444	13%

TABLE 2 – Post-Trim Tree-Related Outage Event Reduction

Q. How does this reduction compare to results under the prior trimming practice?

A. The past practice of trimming a "clearance circle" around conductors provided only a 13% reduction in tree-related events in the year following trimming as compared to the average number of events in the three-years preceding trimming

Q. How did the circuits trimmed as part of the ETTP perform in comparison to the system during the March 8, 2017 wind storm?

A. The circuits trimmed as part of the ETTP performed much better than the remainder of the system as shown in Table 3.

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	Non-ETTP Circuits	ETTP Circuits	ETTP Improvement
Outages/circuit	4.2	1.9	54%
Outages/Customer	0.0062	0.0037	41%
Minutes of Interruption/Customer	1,591	864	46%

TABLE 3 – Circuit Performance during March 8, 2017 Wind Storm

Q. What has been the reduction in wire down events post-ETTP trimming?

A. Wire downs on the circuits that have been trimmed as part of the ETTP have been reduced by 28% in the year after trimming in comparison to the three-year average preceding trimming.

Q. Please describe some of the productivity initiatives the Company has undertaken to improve the cost-effectiveness of the ETTP and ensure the authorized spend is executed efficiently?

A. The Company has adopted several productivity and process improvement initiatives which have led to significant cost efficiencies, including:

(1) The utilization of GPS technology and the Clearion work management system have provided increased visibility into our contractors' work, allowing us to partner with them in making process improvements in both work planning and execution.

(2) The implementation of weekly huddles with scorecards for each of our contractors has allowed for improved communications and the ability to eliminate roadblocks before becoming a detriment to productivity.

(3) The optimization of pull-out locations, which allowed tree trimmers to reduce drive time to the worksite.

(4) An updated wood haul process whereby the Company would leave wood that could be used by customers. This process was also intended to mitigate the spread of tree diseases and invasive species.

(5) The use of fuel trucks at the contractor pull-out locations which made it possible for the tree trimmers to be on the jobsite for longer periods of time by not having to take time in the beginning or end of the day to fuel their own vehicles.

(6) The hiring of chip tippers allowing for the extension of the workday by eliminating the need for tree trimmers to dump chips at the end of the day.

(7) The continued utilization of specialty equipment to improve efficiency and reduce manual work such as: mowers, side trimmers, backyard buckets, off-road buckets (70' and 55'), and mini-skid steer.

Q. What are the savings from these initiatives?

A. The initiatives in 2017 provided a 7.5% average annual improvement in productivity as measured by earned hours.

Q. What are earned hours?

A. Earned hours is a metric created by the Company to track contractor productivity. The Company has 50 units to represent all the types of work executed in the field. Each unit has a standard time associated, which is the expected amount of time required to complete that unit. Every week, contractors submit the number of units completed, by day of week, by circuit, and the hours it took to complete the units.

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The expected value of time it would take to complete the units is compared to the actual hours it took to complete the units determining the Earned Hours.

Q. Are the improvements in productivity sustainable?

A. Yes. The improvements are sustainable and have been implemented by the Company's contractors to ensure they achieve the expected levels of productivity while executing contracts.

Q. Are there additional improvements the Company would like to make related to its tree trim program?

A. Yes. Further improvements are needed to achieve the Company goals related to safety, reliability, and cost reduction. Currently, the Company continues to evaluate a series of initiatives. The value in the shift in contracting structures from time and equipment to fixed-bid will continue to be assessed as the Company develops the contracts for the 2019 Plan in the third quarter of the year. Other initiatives include expanding the use of herbicides to control undesirable vegetation in the right-of-way, which I will discuss later in my testimony. Additionally, we are increasing our efforts in partnering with local communities to clear alleys to improve bucket truck accessibility and lower costs, as was conducted with the City of Highland Park in early 2018. We are also testing the effectiveness of circuit shutdowns to reduce the risk of working near energized lines and increase the pace at which tree trimmers work. This initiative will improve efficiency of trimming; however, it will result in customer outages during the time of trimming which could lead to increased customer complaints.

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Vision for Tree Trimming

Q. How does the Company benchmark in reliability?

A. As discussed by Witness Bruzzano in his testimony, the Company is in the fourth (bottom) quartile of the industry based upon customer minutes of interruption, System Average Interruption Duration Index – excluding Major Event Days (SAIDI – excluding MEDs).

Q. What is the biggest root cause of outages?

A. As discussed in the Company's Five-year Plan, tree interference is the leading driver of customer outages. Tree-caused outages account for two-thirds of the time that customers spend without power; thus, the successful execution of the tree trimming program will allow the Company to significantly improve the overall reliability of electric service.

Q. What is the best way to reduce tree related outages?

A. A robust tree trimming program is needed to address system reliability including customer minutes of interruption and the number of customer interruptions. The program must be funded to maintain a tree trim cycle that permits the subsequent trimming of a circuit before the trimmed trees grow into the Company's wires and become hazards.

Q. What is the Company's vision for its Tree Trimming program?

A. The Company remains firmly committed to achieving a five-year cycle. This will be accomplished by continuing to improve the efficiency with which trimming work is

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executed and by working through the regulatory process to obtain the funding to support the program. As stated by Company Witness Bruzzano in his testimony regarding the Company's Global Prioritization Model, tree trimming is the highest priority investment. No other program in the Company's portfolio of distribution projects will have a greater impact on mitigating risks, improving system and customer reliability, and managing the costs of operating the Company's electric distribution system.

Q. How many miles need to be trimmed annually to achieve a five-year cycle?

A. DTE Electric currently needs to trim approximately 6,538 miles per year to achieve the optimal five-year cycle for distribution circuits.

	Overhead Miles	Cycle Length (years)	Cycle Mileage (miles / year)
Distribution Circuits	28,459	5	5,692
Subtransmission Circuits	2,539	3	846
Total	30,998	4.75	6,538

TABLE 4 – Tree Trimming Cycle Length

Q. What is the Company's current trimming cycle?

A. In 2017, the Company cleared 3,601 miles which equates to an effective eight and a half-year cycle. Based on funding and miles trimmed in 2015-2017 the system is on an effective nine-year cycle.

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Q. Why is the Company proposing to move to a five-year cycle?

A. The Company typically performs trimming within 15 feet of either side of the distribution pole centerline, or approximately 10 feet from the conductors. The Company's target of a five-year cycle is based on the following facts:

(1) As discussed later in my testimony, trees near the Company's distribution equipment grow approximately 10 feet on average in five years.

(2) The five year-cycle provides a reasonable and acceptable level of tree-to-conductor contact comparable to the industry standard of 10% - 15%. Tree-to-conductor contact represents the likelihood of any portion of the tree touching the conductor. A tree-to-conductor contact level of 10% - 15% denotes the estimated average percentage of trees in contact with the overhead electrical facilities across the entire distribution system when the recommended cycle length and clearance standards are reached.

Q. How does the Company's targeted cycle length compare to the industry benchmarks?

A. The Company's targeted five-year cycle on distribution circuits is comparable to the actual industry average of 4.9 years, per the report published by CN Utility Consulting, Inc. (CNUC) - Distribution Utility Vegetation Management Benchmark Survey Results 2016 - as shown in Chart 1. Furthermore, all but six of the participating companies target a cycle of five years or less. Furthermore, the Company's own benchmarking efforts indicated an average actual cycle length of 5.2 years.

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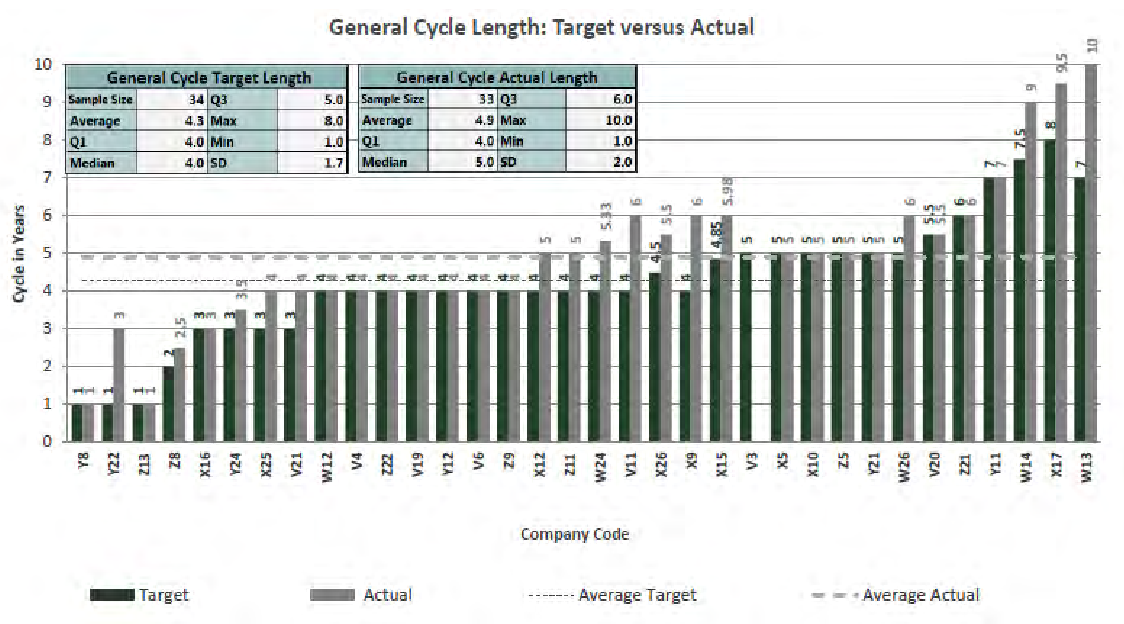

CHART 1 – CNUC Benchmark Study – General Cycle Length

Surge Proposal Description

Q. When does the Company propose to achieve a five-year cycle?

A. The Company is proposing a seven-year surge in the tree trimming program to achieve a five-year cycle and eliminate the backlog of miles yet to be trimmed as part of the Enhanced Tree Trimming Program (ETTP) by 2026.

Q. What is meant by “backlog” and “on-cycle”?

A. Backlog refers to the circuit miles that have yet to be trimmed as part of the ETTP. On-cycle means that the circuit miles have been trimmed within the last five years.

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Q. Why will it take a seven-year surge to achieve a five-year trimming cycle?

A. The number of years it will take to complete the Surge is primarily driven by three factors:

(1) The funding level provided to the program

(2) The resources available to trim nearly 31,000 miles of overhead circuits

(3) Ensuring that any mile previously trimmed as part of the ETTP will remain on a five-year cycle.

Q. Will the Company prioritize circuits already trimmed as part of the ETTP before the circuits on the backlog?

A. Yes. Circuits already trimmed as part of the ETTP will be maintained on a five-year cycle, while also addressing the backlog of circuits that have yet to be trimmed as part of the Company's ETTP.

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Q. How many miles will be addressed annually on the backlog compared to those on-cycle during the Surge?

A. Chart 2 shows the miles the Company intends to trim from the backlog of circuit miles that have yet to be trimmed as part of the ETTP and the miles that are on-cycle and have been trimmed as part of the ETTP.

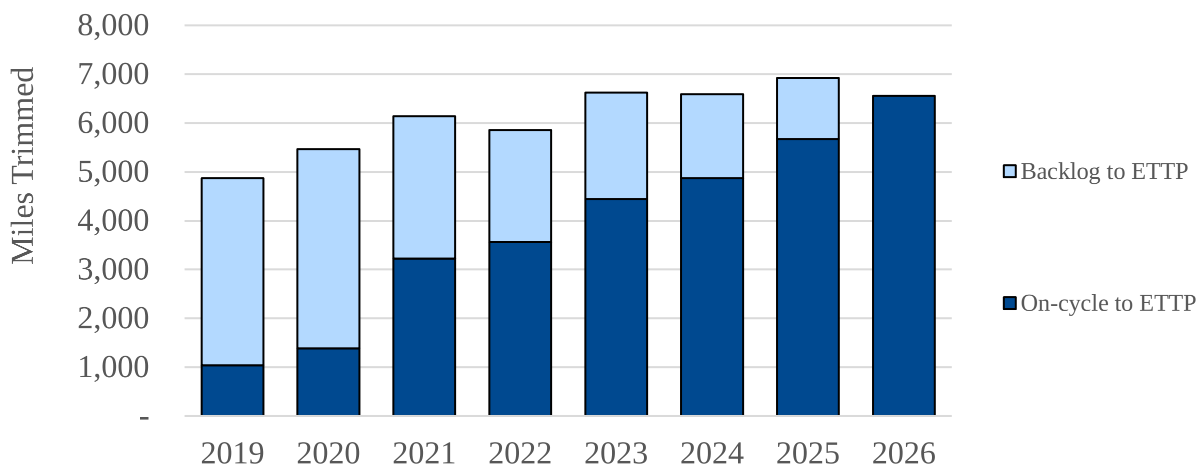

CHART 2 – Miles Trimmed During Surge and First Year of Post-Surge

Q. Are the specifications applied consistently throughout the Surge?

A. Yes. Tree trimming specifications are applied consistently throughout the Company's service territory. The Company trims circuits to maintain clearance for one five-year cycle worth of growth which, on average, necessitates ten feet of clearance to the outermost conductor. The required clearance is species-specific.

Q. How was the average tree regrowth rate determined?

A. The regrowth rate is based on the Company's historical experience and was reaffirmed during a regrowth study performed by ECI, a nationally recognized expert in utility vegetation management, during the first quarter of 2017. The rate accounts for the physical orientation of specific trees and the corresponding types of trimming performed as shown in Chart 3. This average growth is a function of the tree species mix in the Company's service area. The inventory of common species was developed by ECI through a visual sampling of the vegetation surrounding the Company's overhead lines. On average, in a five-year period, a tree in the Company's service territory will grow ten feet upwards and approximately seven feet outwards. The average growth rate of the common tree species in the Company's service territory is provided in Table 5.

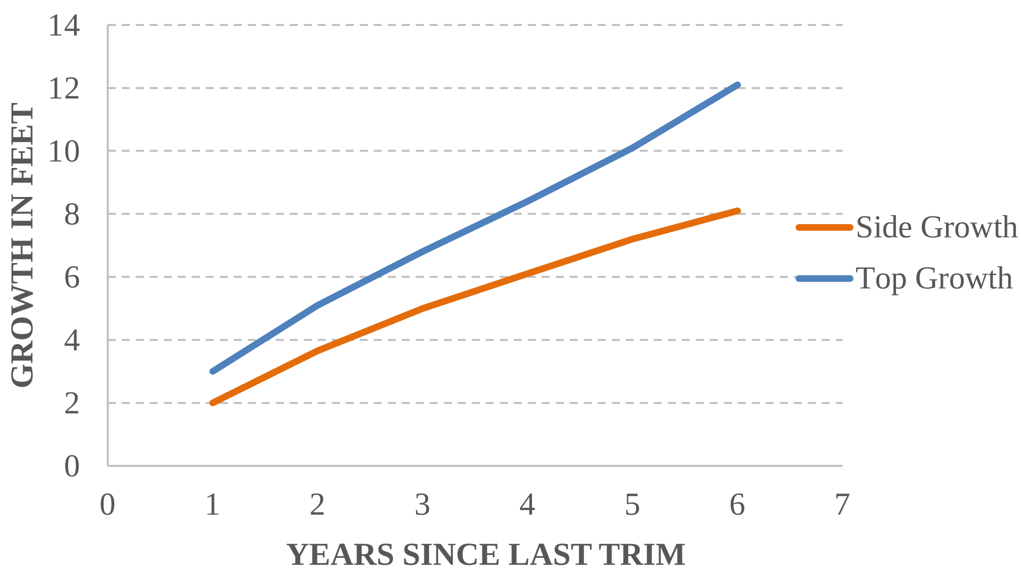

CHART 3 – Average Tree Regrowth Rate on the Electric Distribution System per ECI

Tree Species	Pruning Type	Inches of Regrowth by Age of Sprout					
		1 Year	2 Years	3 Years	4 Years	5 Years	6 Years
Box-elder	Side	30	53	78	97	117	136
	Top	53	91	124	157	185	213
Maple, Norway	Side	21	37	51	67	79	90
	Top	33	59	85	112	134	153
Maple, red	Side	17	33	50	65	81	95
	Top	27	52	80	106	126	142
Maple, silver	Side	37	60	89	109	129	144
	Top	41	72	105	140	170	194
Maple, sugar	Side	19	36	55	72	87	100
	Top	30	51	74	97	115	132
Tree-of-heaven	Side	18	35	53	71	89	103
	Top	40	68	92	113	135	157
Elms	Side	37	61	81	99	115	134
	Top	54	97	132	168	200	240
Honeylocust	Side	20	37	51	66	82	96
	Top	31	54	77	95	111	125
Walnut, black	Side	23	45	63	78	91	103
	Top	72	106	134	154	174	191
Mulberry	Side	36	64	83	104	121	141
	Top	46	82	107	129	154	174
Spruce, Norway	Side	16	26	37	44	50	57
	Top	15	28	44	56	71	86
Spruce, blue	Side	16	26	37	44	50	57
	Top	8	16	24	32	39	48
Pine, red	Side	11	20	28	36	44	55
	Top	12	22	34	46	61	74
Pine, eastern white	Side	9	19	29	40	47	56
	Top	18	35	53	69	85	102
Cottonwood, eastern	Side	28	51	78	99	115	129
	Top	49	78	110	133	150	165
Pear, Bradford	Side	12	26	40	53	63	75
	Top	23	44	66	89	106	120
Oak, white	Side	15	29	38	47	58	67
	Top	17	31	42	55	66	76
Oak, red	Side	20	38	54	70	84	99
	Top	23	46	65	81	98	117

TABLE 5 – Average Regrowth Rate for Common Tree Species on the Company's Electric Distribution System per ECI

Q. Can you provide additional information on ECI and how their work relates to this testimony?

A. ECI was founded in 1972 and is a leading provider of vegetation management consulting and field services to electric and gas utilities, actively consulting and partnering with over 40 utilities nationwide, including Consumers Energy. The Company contracted ECI's consulting services in 2015 to improve the management of right-of-way vegetation by applying industry best practices to increase service reliability, reduce risks, and lower the costs associated with managing the vegetation around the Company's lines.

Q. Why is a three-year cycle needed on subtransmission circuits?

A. The three-year cycle is maintained because of the high customer impact of subtransmission lines. A trouble event on a subtransmission circuit can potentially cause an entire substation to lose power, which would affect, on average, over 3,600 customers, while a trouble event on a distribution circuit would affect, on average, approximately 700 customers. Therefore, outage events on subtransmission lines have a severity effect five times greater than a similar outage event on a distribution circuit.

Benefits of the Surge Proposal

Q. How will customers benefit from reducing the tree trimming cycle length to the industry benchmark of a five-year cycle?

A. Reducing the tree trimming cycle length to five years will provide tree-related benefits and savings in multiple ways:

Line
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(1) Lower customer complaints. The Company recognizes and acknowledges that tree-related outage and non-outage events are a major issue for our customers that can be rectified through the tree trim program and requested funding.

(2) Fewer wire down events, resulting in improved safety

(3) Fewer outage and non-outage events, leading to a positive impact on reactive O&M and capital costs. This will also allow for the re-allocation of resources to other necessary work across the Company's distribution system.

(4) Lower future trimming costs as the number of trees growing within the right-of-way are trimmed or removed more frequently, resulting in the need to remove less wood from the trees near the Company's lines.

(5) Lower customer costs as tree-related outages are reduced. The improved reliability will reduce downtime for customers' manufacturing processes, allow commercial businesses to remain open, and reduce the inconveniences that residential customers experience.

Q. How much value does the program provide to customers?

A. The net present value ("NPV") analysis as shown in Exhibit A-22 Schedule L1 **Revised**, which compares the NPV of continuing the current tree trimming practices and investing in the Surge program, indicates the program is $~~46~~ **67** million favorable to customers.

Q. Was the economic value to customers of the improved reliability from the Tree Trimming Surge taken into consideration when determining the NPV?

A. No. The value of the program was based upon the forecasted reduction in revenue requirement that customers would receive through 2040 due to the investment in the

Line
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Tree Trimming Surge program. The analysis did not take into consideration the additional economic benefits that derive from improved reliability as could be calculated utilizing the Interruption Cost Estimation (ICE) Calculator developed by Nexant and the Lawrence Berkeley National Lab (Lawrence Berkeley Study) as described by Company Witness Bruzzano.

Q. How much does the Company expect to reduce costs per line mile trimmed upon achieving a five-year trimming cycle?

A. Based on the work study completed by ECI, the Company expects its cost per line mile to decrease, on average, by 40% compared to the initial trimming conducted as part of the ETTP.

Q. How many tree-related trouble events does the Company expect to reduce upon achieving a five-year cycle through the investment surge?

A. Based upon details from the Company's outage and dispatch management systems, the Company typically attributes approximately 56,900 outage and non-outage events to trees, or 25% of its roughly 225,000 average annual outage and non-outage events the Company experiences. Upon completion of the Surge, the Company expects the tree-related events to be reduced by approximately 40%.

Outage and Non-Outage Events	Pre-Surge 2012-2016 Average	Post-Surge 2026	% Reduction
Tree-Related	56,913	33,649	40.9%

TABLE 6 – Average Annual Outage and Non-outage Events

Line
No.

Q. What reliability improvements will be provided through the Surge program?

A. The Company expects a 40% reduction in tree-related All-Weather SAIDI. This reduction is driven by fewer tree-related events.

Q. How did the Company determine the percentage reduction in events upon completion of the Surge?

A. The Company based the 40% reduction upon:

(1) The circuits that have been trimmed as part of the ETTP have shown a 47% reduction in events in the year after trimming as compared to the three years prior to trimming the circuit.

(2) A study ECI conducted on behalf of the Company indicated a reduction in the cycle length from an effective eight and a half-year cycle to a five-year cycle would reduce events by 35%.

(3) Benchmarking of peer utilities suggests an improvement in event reductions in excess of 50%.

Q. What cost savings will be provided through the Surge program?

A. At the completion of the Surge, tree-related O&M and capital costs for reactive maintenance and storm will be lower. With fewer tree-related events, the need for tree crews and Service Operations' overhead crews will be reduced. There will be less of a need to repair and replace assets on the system that have failed because of tree interference. Table 7 shows current O&M and capital cost compared to the projected costs upon completion of the Surge, excluding inflation.

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Estimated Tree-related Annual Cost Savings ($ millions, excluding inflation)			
Cost Category		Current Cost	Post-Surge 2026
Tree-Related O&M	Tree Trim Reactive	$11.4	$6.7
	Tree Trim Storm	$10.5	$6.2
	Other DO – Service Operations Storm and Trouble	$11.6	$6.9
Tree-Related Capital	Tree Trim Reactive	$4.6	$2.7
	Tree Trim Storm	$18.5	$10.9
	Other DO - Service Operations Storm and Trouble	$34.6	$20.4

TABLE 7 – Tree Trimming Surge Cost Savings

Q. What will reliability performance be if the Surge program is not funded?

A. Without an increase in funding, the backlog of circuits in need of trimming as part of the ETTP will not be addressed. In 2026, there will be nearly a 10,000-mile backlog of distribution circuit miles that have yet to be trimmed as part of the ETTP.

The proposed funding level, absent the Surge, would allow the Company to maintain an effective 11-year cycle. If the Surge funding is not approved and an 11-year cycle becomes the standard for the Company, outage and non-outage events, including wire downs, will continue to grow, customer satisfaction will erode, and complaints to the

Line
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MPSC will increase. Ultimately, tree-related reactive and storm costs will increase by approximately 45%, excluding inflation, taking away from the funds that were to be allocated to planned investment and maintenance activities.

Q. Does it cost more to trim a circuit if it is not trimmed on-cycle?

A. Yes. As referenced by the MPSC Staff in 2013 Ice Storm Report, Case No. U-17452, deferring maintenance results in cost escalation as described in the May 1997 study funded by International Society of Arboriculture ("ISA") and conducted by ECI, LLC – The Economic Impacts of Deferring Electric Utility Tree Maintenance. Table 8 shows the relative cost, excluding inflation, of deferring maintenance beyond the optimum time – five years after the previous trim for the Company. By deferring maintenance, the Company will need to allocate more funds to trimming the deferred work in a subsequent year.

Timing of Trimming	Years since last trim	Relative Cost
Optimum	5	$1
1-year past optimum	6	$1.16 to $1.23
2-years past optimum	7	$1.30 to $1.43
3-years past optimum	8	$1.40 to $1.59
4-years past optimum	9	$1.47 to $1.69

TABLE 8 – Projected Impact on Cost of Deferring Maintenance

Q. Will it take more resources to trim a circuit if it is not trimmed on-cycle?

A. Yes. Longer tree trimming intervals result in higher tree trimming cost over time, as also described in the May 1997 ISA study. As illustrated in Diagram 1, as the time since last trim continues to grow, the work becomes more complex as trees begin to interfere with the conductors.

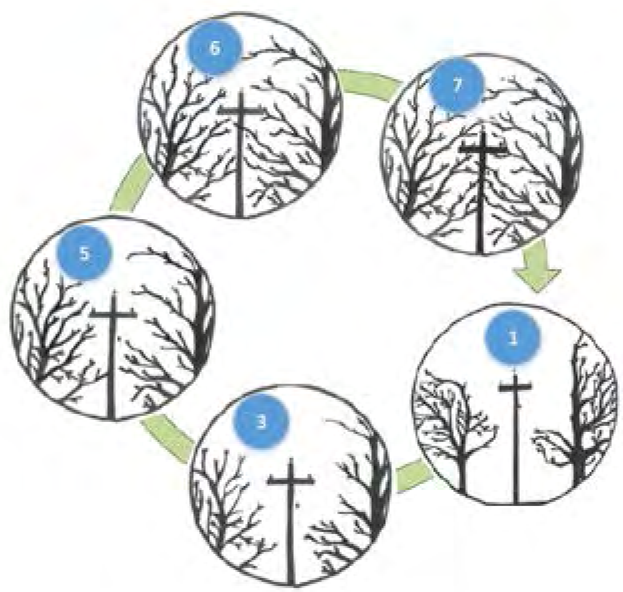

DIAGRAM 1 – Illustrative Tree Growth Impact on Complexity

(Years since Last Trim)

Q. Was a longer cycle considered?

A. Yes. A longer cycle was considered. However, lengthening the overall cycle beyond five years increases the level of tree-to-conductor contact. Excessive tree contact will result in a significant increase in tree-related events and customer minutes of interruptions. The five year-cycle provides a reasonable and acceptable level of tree-to-conductor contact, as shown in Table 9. The Company targeted the industry

standard of 10% - 15% tree-to-conductor contact level as stated in the May 1997 ISA study.

Clearance (in feet)	Est. %Tree Contact Avg. All Circuits by Cycle Length					
	1 Year	**2 Year**	**3 Year**	**4 Year**	**5 Year**	**6 Year**
1	100.0	100.0	100.0	100.0	100.0	100.0
2	77.3	86.8	90.8	92.9	94.3	95.1
3	50.0	66.1	75.1	80.6	84.0	86.5
4	27.0	44.7	56.9	65.6	71.5	75.7
5	13.5	27.9	41.2	51.1	58.8	64.5
6	5.2	16.3	28.2	38.4	46.8	53.6
7	2.3	9.8	18.9	27.4	35.8	42.8
8	0.7	5.1	11.5	18.4	25.8	32.6
9	0.3	2.5	7.3	12.7	18.5	24.8
10	0.1	1.3	4.4	8.2	12.7	17.8
11	0.1	0.7	2.6	5.3	8.7	12.9
12		0.3	1.4	3.2	5.8	9.1
13		0.2	0.7	2.0	4.0	6.6
14		0.1	0.5	1.4	2.8	4.6
15		0.1	0.4	0.9	1.9	3.3

Greater than 15% Contact

DTE target 5-year cycle

Effective 7-yr cycle

TABLE 9 – Likelihood of Tree-to-Conductor Contact

Q. What would be the expected tree-to-conductor contact on a seven-year cycle?

A. Understanding that average tree regrowth is two feet per year, the Company would expect a seven-year cycle to have an equivalent clearance of a five-year cycle with six feet of clearance. This would equate to the likelihood of tree-to-conductor contact in excess of the industry standard at 46.8%. Upon achieving a seven-year cycle in 20 years, system performance would only be improved by 15%.

Q. Was a larger tree-to-conductor clearance considered?

A. Yes. A larger clearance to the conductor was considered as a method for extending the cycle beyond five years; however, costs and customers complaints would increase with the increased removal of vegetation from customers' properties. The Company expects that the cost to trim an additional two feet of clearance would be similar to the added cost of deferring maintenance a year beyond the optimum time of trimming, resulting in an increase in cost per mile by 16% - 23% as depicted in Table 8.

<u>Funding Required</u>

Q. Can you please describe Exhibit A-13, Schedule C5.6, page 3, "Tree Trim Expenses"?

A. This page shows the details of the calculation supporting Tree Trimming expenses for the projected test period. The amount is broken down into three categories: maintenance and staff, herbicide, and reactive maintenance. Column (c) shows the actual expenses for 2017, and inflation is applied to this expense in columns (d) to (f). The inflation rates are supported by Company Witness Uzenski. The O&M adjustments for the trimming of miles approved in Case No. U-18255 and the implementation of an herbicide program are included in Lines (2) to (3) column (g). Column (h) shows the result of all the adjustments applied to the historic period, which is used to forecast the 12-month period ended April 30, 2020. The total amount requested for the projected period is $95.1 million. These amounts are included in Exhibit A-13, Schedule C5.6 on Line (18) as a part of total distribution O&M. The amount requested in Exhibit A-13, Schedule C5.6 does not include the total funding needed to achieve a five-year cycle which will be discussed later in my testimony.

Line
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Q. How much funding was included in Case No. U-18014 to trim trees in 2017?

A. In Case No. U-18014, the tree trimming program was funded to $75.2 million. The projected test year in that rate case was August 1, 2016 through July 31, 2017.

Q. How much funding was included in Case No. U-18255 to trim trees in 2018?

A. In Case No. U-18255, the tree trimming program was funded to $83.8 million for a total increase of $8.6 million above the funding level approved in the 2017 order with the goal of increasing the number of miles trimmed year-over-year. For reference, the projected test year in Case No. U-18255 was November 1, 2017 through October 31, 2018.

Q. How much funding was included in Case No. U-18014 for reactive maintenance 2017?

A. In Case No. U-18014, the tree trimming program included $6.0 million for reactive maintenance in 2017.

Q. How much funding was included in Case No. U-18255 for reactive maintenance?

A. In Case No. U-18255, the authorized tree trimming amount included $6.3 million for reactive maintenance.

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Case No.	Year	Program Funding excluding Reactive Maintenance	Reactive Maintenance	Total Program Funding
U-18014	2017	$69.2	$6.0	$75.2
U-18255	2018	$77.5	$6.3	$83.8
Funding Increase		$8.3	$0.3	$8.6

TABLE 10 – Tree Trimming Spend ($ million)

Q. How much did the Company spend on Reactive Maintenance in 2017?

A. In 2017, the Company spent $11.4 million on reactive maintenance, or $5.4 million more than the amount included in Case No. U-18014 for 2017, and $5.1 million more than the 2018 forecasted spending in Case No. U-18255.

Q. How much funding is the Company requesting for Tree Trimming Maintenance and Staff (Program Funding excluding Reactive Maintenance and Herbicides)?

A. The Company is requesting inflation adjusted funding on $77.5 million, equating to a projected test year spend of $80.9 million on the Tree Trim Program's Maintenance and Staff. This amount includes the cost of trimming circuit miles and approximately $6.3 million for staffing, auditing, planning, and meeting customer requests. This amount does not include the total needed to trim the circuit miles needed to achieve a five-year cycle which will be discussed later in my testimony.

Line
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Q. How much funding is the Company requesting for Reactive Maintenance?

A. The Company is requesting inflation adjusted funding based on the 2017 historical spend of $11.4 million. The Company expects to spend $12.2 million on reactive maintenance in the projected test year.

Q. How much funding is the Company requesting for Herbicides?

A. The Company is requesting $2 million for the Herbicide program in the projected test year. This program will be discussed in more detail later in my testimony.

Q. Do these requests include the Surge funding?

A. No. The amounts requested in the Exhibit A-13, Schedule C5.6 do not include the total amount needed to fund the tree trimming program to achieve a five-year cycle.

Q. Including the Surge, what is the total requested funding in 2019 and 2020?

A. In 2019 and 2020, the Company is requesting a $137.5 million and $171.1 million as
Revised
depicted in Exhibit A-22, Schedule L1, Line (5), columns (c) and (d), respectively.

Q. What is the requested funding amount for the Surge in 2019 and 2020?

A. Of the $137.5 million in 2019 and the $171.1 million in 2020, the Company is requesting the deferral of $43.3 million and $74.1 million in Surge funding as
Revised
depicted in Exhibit A-22, Schedule L1, Line (11), columns (c) and (d), respectively.

Q. What is driving the increase in Reactive Maintenance expense beyond what was included in Case No. U-18255?

A. Tree Trimming reactive maintenance expense has been escalating as a result of increased requests as shown in Chart 5. Reactive maintenance, which is primarily driven by increased customer-initiated requests for tree-related work, has increased 62% over the past three years. As shown in Chart 6, the number of years that have passed since the last trim is indicative of the number of customer initiated requests.

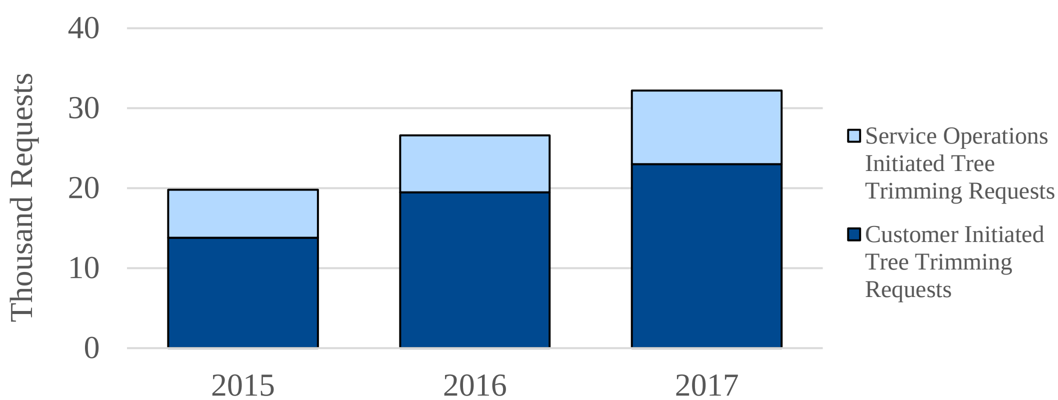

CHART 5 – Reactive Maintenance Tree Trimming Requests

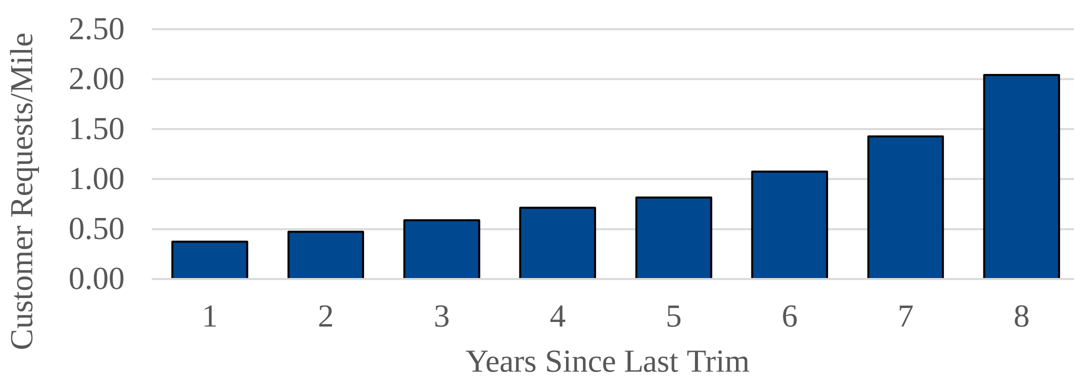

CHART 6 – Customer Initiated Requests per Mile by Years since Last Trim

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Q. What is the Company's estimated cost per mile for Surge tree trimming?

A. The Company expects the average cost to trim a distribution circuit that is part of the ETTP backlog to be approximately $20,160/mile, excluding staffing, auditing, planning, meeting customer requests, and inflation. The circuits that are "on-cycle" and have already been trimmed as part of the Company's ETTP are expected to cost 40% less.

Q. How does this estimated cost compare to the Company's historical ETTP cost per mile for distribution circuits?

A. Excluding staffing, auditing, planning, and meeting customer requests, the forecasted cost per mile to trim the backlog is higher than historical average as shown in Table 11. The backlog cost is expected to increase as a result of the time that has passed since last trim and the mix of resources.

	2016 Actual	2017 Actual	2018 Forecast	Historical Average	Backlog
Cost per Mile ($ k/mile)	$18.9	$18.6	$18.7	$18.7	$20.2

TABLE 11 – Distribution Circuit Cost per Mile to Trim

Q. How did the Company develop this cost estimate?

A. The Company hired ECI to conduct a density study on the circuits that have not yet been trimmed as part of the ETTP. Using this data, the average cost was obtained by aligning the average density in trees per mile with the average historical cost to trim a tree in each service center area. As demonstrated in Chart 7, density is a significant driver of the cost to trim.

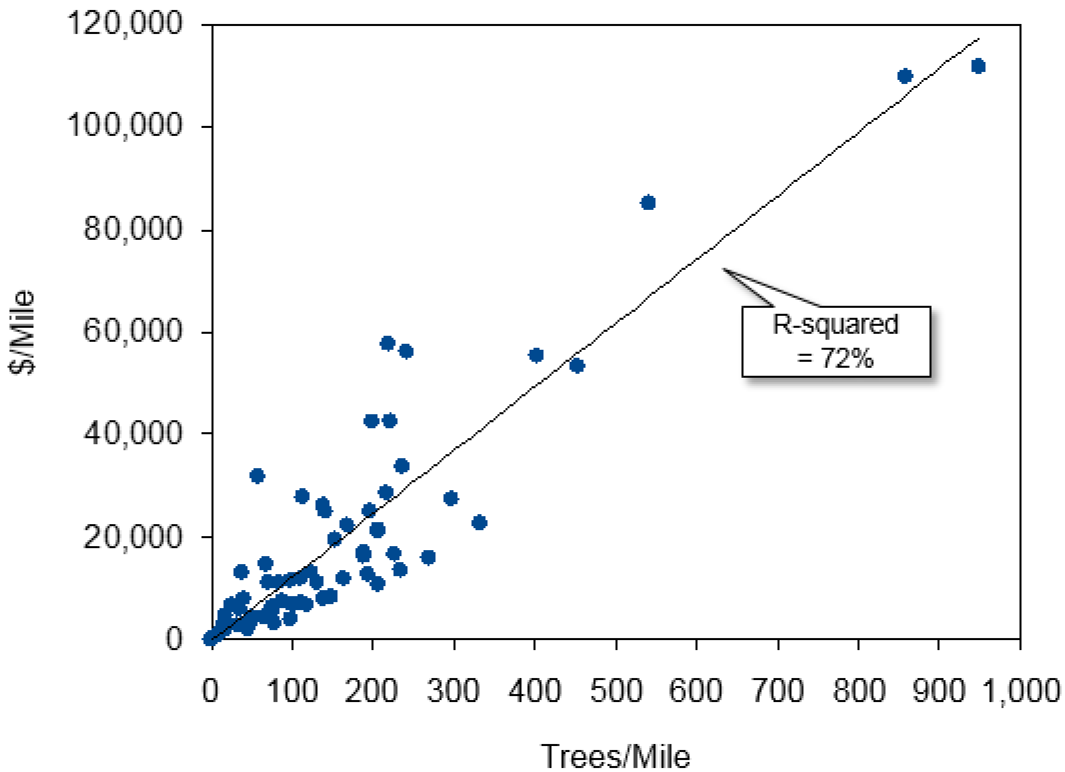
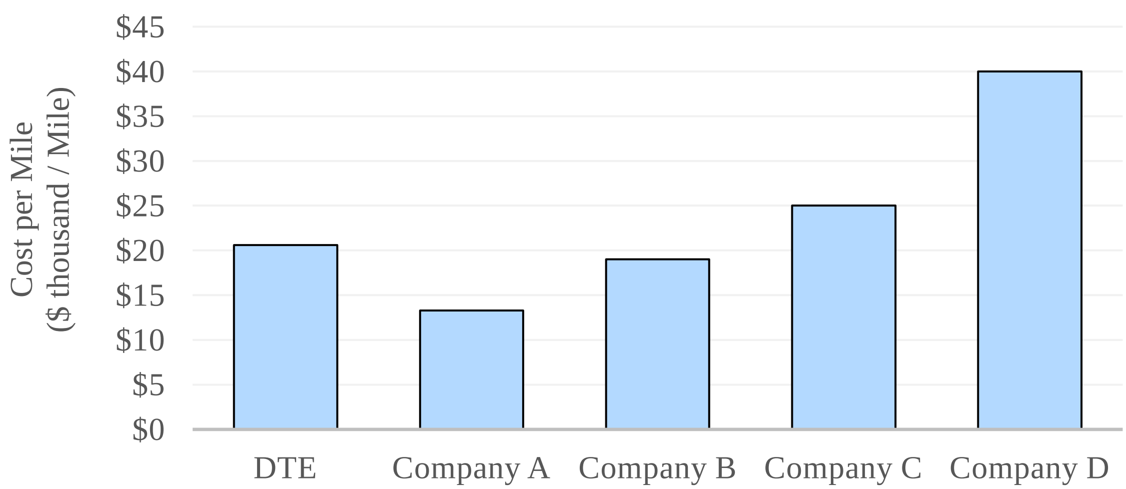


CHART 7 – Density as a Driver of Cost

Q. How does this estimate compare to the Company's benchmarks?

A. The Company has benchmarked with several companies. Some provided the Company with cost per line mile information that ranged from approximately $13,000-$40,000/mile as shown in Chart 8. Other companies stated that they perform the work on capital and do not track it on a per mile basis. In addition to speaking to other utilities, the Company also has been able to confirm the reasonableness of our estimates from consultation with ECI and through earned value calculations on each circuit (earned value was described earlier in the testimony).



Density (trees/mile)	187	110	134	100	169

CHART 8 – Cost to Trim Backlog of Miles to ETTP

Q. Why are the costs forecasted to increase?

A. Cost forecasts are based on tree density, work location, and the type of work to be conducted. The Company expects to sustain the productivity and cost improvements

that have been made to-date, but the Company expects upward pressure on costs as the circuits to be trimmed have higher tree density, more backlot work, and more climbing required as depicted in Tables 12 and 13.

Service Center	Miles Trimmed to ETTP	Miles of Backlog to ETTP	Avg. Tree Density (trees/mile)	Work Location (% Backlot)	Work Type (% Climbing)
Ann Arbor	787	1,283	212	60%	64%
Caniff	342	1,087	235	79%	69%
Howell	894	1,684	223	58%	64%
Lapeer	1,176	1,443	175	64%	67%
Marysville	1,195	1,609	126	51%	51%
Mt. Clemens	717	1,644	151	67%	66%
North Area	1,258	1,881	92	54%	56%
Newport	778	929	118	60%	66%
Pontiac	688	2,087	256	67%	73%
Redford	678	2,408	284	79%	81%
Shelby	394	861	159	63%	62%
Western Wayne	602	2,066	184	72%	76%
DC System	12,900	15,594	187	64%	66%

TABLE 12 – Miles Trimmed/To be Trimmed and Cost Drivers

Line No.

	Weighted Avg. Tree Density (trees/mile)	Weighted Avg. Work Location (% Backlot)	Weighted Avg. Work Type (% Climbing)
Miles Trimmed to ETTP	174	62%	65%
Miles of Backlog	195	66%	68%
% Increase in Complexity	21	4%	3%

TABLE 13 – Increased Complexity

Q. Is the Company capable of spending the increased funding?

A. Yes. As shown in Table 14, the Company has spent more than the authorized tree trimming spend since 2016 and will be able to cost effectively complete the tree trimming required at the increased funding level.

Tree Trimming Spend ($ millions)			
	Authorized	Actual	Variance
2016	$65.7	$74.2	13%
2017	$75.2	$84.3	12%

TABLE 14 – Tree Trimming Authorized vs. Actual Spend

<u>Funding Mechanism</u>

Revised

Q. Can you please describe Exhibit A-22, Schedule L1, pages 1 and 2, "Projected Value of Tree Trim Program"?

A. These pages show the details of the calculation supporting the Projected Value of the Tree Trim Program through 2040. The page is broken up into four sections: Surge

Line
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Program O&M Costs, Status Quo Program O&M Costs, Surge Program Capital Costs, and Status Quo Program Capital Costs. The first section depicts the tree-related O&M costs for the Surge Program. Line (2) depicts the cost to trim the miles needed to achieve a five-year cycle. Line (3) shows the cost of the continuation of the Herbicide Program and is equal to Line (14) as the Herbicide Program will be continued regardless of an approval of the Surge program. Lines (4), (8), and (9) depict the Tree Trim Reactive Maintenance, Tree Trim Storm, and Other DO Tree-Related O&M Costs, respectively. These costs are dependent upon the projected event reduction resulting from the surge in investment in the Tree Trim Program. Line (6) conveys the Credit to the Regulatory Asset. This is calculated by taking the Total Tree Trimming O&M Spend in Line (5) and subtracting Line (16), which is the inflation adjusted tree trimming spend for the Status Quo Program. The next section demonstrates the tree-related O&M costs for the Status Quo Program, which simply grows at the rate of inflation for Line (16). Lines (15), (17), and (18) are impacted by the Company's ability to maintain limited overhead circuit miles on a five-year cycle. Because an inflation adjusted program does not provide adequate funding to achieve a five-year cycle on the entire system, the reactive, storm, and trouble costs escalate. Line (20) calculates the respective O&M savings of the Surge program as compared to the Status Quo. The third section conveys the Surge program capital costs. The costs shown in Lines (22), (23), and (24) are driven by events and the respective reduction in events expected upon investing in the tree trimming Surge. The fourth section represents the Status Quo Program capital costs. Line (27) conveys the amount of tree trimming charges when trimming in support of replacing an asset on a Blue Sky day, while Line (28) is for Storm spend only. Line (29) depicts

Line
No.

the capital spent by the Service Operations organization as a result of tree-related events. Ultimately, the capital savings from investing in the tree trimming Surge program is shown on Line (31).

Q. What is the total forecasted cost of tree trimming from 2019 through 2025?

A. Tree trimming costs are expected to be approximately $1.13 Billion from 2019 to 2025.

Q. How much of the cost will be recovered through base rates?

A. $722 million is expected to be recovered through base rates from 2019 to 2025.

Q. How is the base rate cost recovery calculated?

A. The total amount requested for the projected test period ending on April 30, 2020 of $95.1 million is inflated at 3% per year.

Q. How much cost is the Company expecting to recover outside of base rates?

A. The Company is proposing to recover the surge cost of $410 million above base rates through an alternative mechanism. See Chart 9 for the costs details.

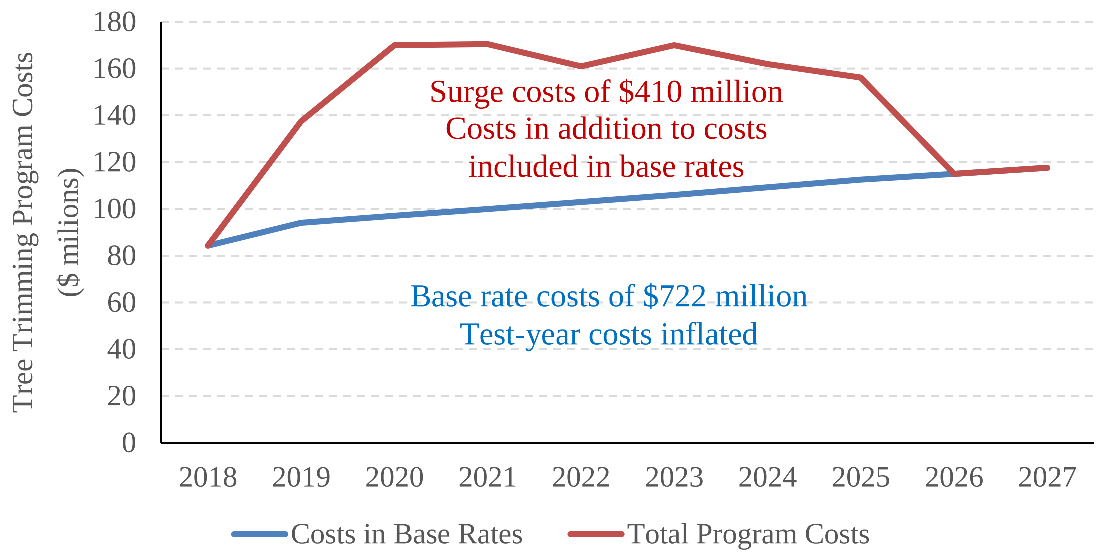

CHART 9 – Tree Trim Program Cost Components

Q. How does the Company expect to recover the program costs above base rates?

A. The Company proposes to defer the incremental cost above base rates of $410 million and amortize it over 14 years as described by Company Witness Uzenski.

Q. Why is the Company proposing to defer and amortize the costs?

A. As previously discussed, the surge investment is intended to lower future reactive costs that would be incurred given the current state of vegetation near or on the distribution system. The deferral recognizes the long-term nature of the program. As the costs are incurred up front and the full savings will not be realized until after the program has matured, the deferral of the incremental costs and subsequent amortization provide a better matching of costs with the anticipated savings, minimizing the cost impact to customers by aligning the increased cost with the

Line No.

realization of savings. Assuming securitization of the regulatory asset, amortization of the deferred costs over 14 years provides a larger net present value benefit to customers than shorter amortization periods and is consistent with the recommendation supported by Witness Solomon.

Q. Is the Company seeking to capitalize the Surge costs?

A. No. The Company is not seeking to capitalize the incremental costs of the Surge.

Q. Is the Company seeking the approval of regulatory asset treatment of the incremental tree trimming expense?

A. Yes. Company Witness Uzenski provides testimony regarding regulatory asset treatment.

Q. Will the Company seek to securitize the regulatory asset?

A. Yes. The Company will propose to securitize the regulatory asset in a future proceeding. Company Witness Solomon provides testimony regarding the securitization of the regulatory asset.

Q. How will the value to customers change if the requested regulatory approvals are not granted?

A. The incremental cost of the investment surge would be expensed immediately. This would result in a misalignment of program cost and savings, and a potential sharp increase in rates as program savings would occur after the expense has been incurred

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Resourcing the Surge

Q. Are sufficient resources available to execute the Surge trimming goals?

A. Yes. Approximately 1,300 tree trimmers are needed to execute the annual scope. Today, the Company employs approximately 850 tree trimmers through five tree trimming contract companies. Approximately 450 additional trimmers will be needed by 2022, and the Company has a plan to secure these resources as they are needed.

Q. How will the tree trimming work be resourced?

A. The Company will use a mix of local and non-local crews to conduct the work. The Company will not be able to achieve the plan through the utilization of local trimmers only, and will need to utilize qualified tree trimming crews from outside of our service territory, especially as the program is ramped up and as local recruitment efforts take hold. The primary long-term plan is to achieve an adequate level of qualified local workers.

Q. What is the Company's plan to secure additional local tree trimmers?

A. The Company has partnered with its tree trimming contractors and IBEW Local 17 to develop and implement a training program to satisfy the demand for qualified tree trimmers. First, new recruits must complete a nine-day boot camp. The boot camp gives participants intensive training and hands-on work experience on subjects such as safety, climbing systems, climbing techniques, arborist equipment, arborist tools, commercial vehicle operation, tree species identification, communication with line crews, customer relations, and aerial rescue techniques. Second, boot camp graduates

enter the Line Clearance Tree Trimming Apprentice Program. The 5,000-hour apprenticeship program, which includes 160 hours of classroom training, is recognized by the Department of Labor as an approved apprenticeship program and is benchmarked throughout the industry. Additionally, continuous education training is required every two years for tree trimmers who have graduated to journeyman status.

Q. What efforts is the Company undertaking to recruit local talent?

A. The Company is partnering with Local 17 and its contractors and reaching out to local high schools such as the Randolph Technical High School to introduce the tree trimming trade to interested candidates. Additionally, the Company recently engaged the Vocational Village at Parnall Correctional Facility in Jackson to develop a pre-apprentice program that will allow returning citizens to enter directly into the apprenticeship program upon leaving the correctional facility.

Herbicide Program

Q. What is the herbicide program?

A. The Company intends to expand the use of EPA-regulated herbicides to replace mechanical removal of vegetation from the right-of-way with a chemical treatment which will only control the tree species with the potential to grow into electrical wires. The Company has based the program off industry best practices that were collected and developed through benchmarking and by working with an outside consultant – ECI.

Line No.

Q. Does the Company currently use herbicides?

A. The Company currently uses herbicides to treat the stumps that remain after the trees are removed from the right-of-way to prevent regrowth. Herbicides for the cut stump treatment are applied immediately after cutting the tree, killing the stump and preventing new growth.

Q. How will the Company alter its herbicide program?

A. The Company will expand the use of herbicides by implementing foliar herbicide treatment, basal herbicide treatment, and dormant stem treatment. These treatments target tree species that pose a risk to the electrical equipment.

Q. Please describe foliar treatments?

A. Foliar herbicide treatment is applied on brush. The herbicide is sprayed on the leaves of the brush using manual or mechanical sprayers. Foliar treatment is intended to prevent growth of brush and the regrowth of brush that was mechanically removed or trimmed during a maintenance cycle. A foliar treatment is typically applied one to two years after trimming and the treatment must be repeated every three to four years to remain effective.

Q. Please describe basal treatments?

A. Basal treatment is applied to established trees to avoid having to mechanically remove them. It is applied on small trees in areas where their fall will not present a hazard to the public, customer property, or electrical equipment. The herbicide is sprayed on the trees' bark using manual sprayers. The herbicide is applied one to

Line
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two years before trimming. Consequently, the treated trees will die and will not need to be removed when the area is trimmed. The treatment will be repeated one to two years prior to the next trimming cycle.

Q. Please describe dormant stem treatments?

A. Dormant stem herbicide treatments are similar to foliar herbicide treatment, being applied on brush using manual or mechanical applicators. Unlike the foliar treatment, the targeted vegetation doesn't need to be in an active growing state to be controlled by the applied herbicides. This treatment is suitable to be used in the cold season, from fall to early spring. The targeted vegetation will gradually die and will not have to be removed when the area is trimmed. As with the foliar treatment, dormant stem treatment is typically applied one to two years after trimming and the treatment must be repeated every three to four years to remain effective.

Q. How much will the herbicide program cost?

A. The Company intends to spend $2 million on its herbicide program in the projected test year. The current cost of the cut stump treatment is included within the cost of maintaining circuits as the resources used to remove a tree simply apply the herbicide as part of the current tree removal process.

Q. How many miles will the company treat with herbicide in the projected test year ending April 30, 2020?

A. The Company intends to treat with herbicides a surface equivalent to approximately 200 miles distributed over the approximately 3,300 miles that were trimmed in 2016.

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Q. What are the benefits of the herbicide program?

A. The herbicide treatment will reduce the cost of maintenance trimming in the right-of-way by reducing tree density. Chart 10 shows herbicide effectiveness to decrease brush density – as brush grows into trees, a lower brush density results into a lower tree density, which is the main driver of tree trimming costs. There are other advantages besides realizing cost savings. As tree density and brush height decreases, the electrical system becomes more reliable and the right-of-way becomes more accessible and safer.

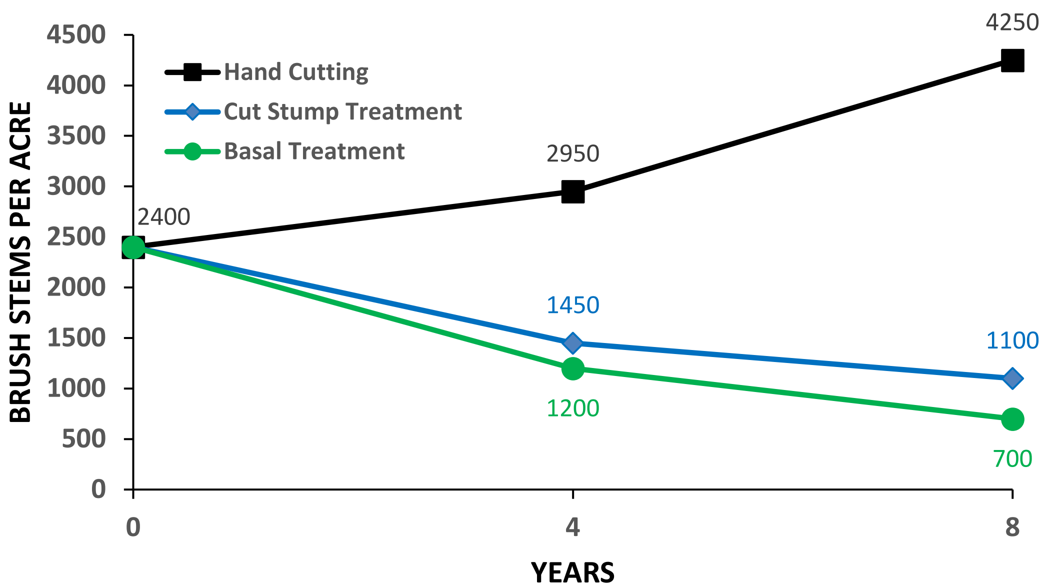

CHART 10 – Effectiveness of Herbicides for Control of Brush Over Time

Q. When does the Company expect to benefit from the herbicide program?

A. The Company expects to realize cost savings on the subsequent cycle of trimming. Foliar treatment benefits are realized three years after application for a five-year trimming cycle. Basal treatment cost benefits are realized two years after application.

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The Company expects the herbicide treatment will reduce the overall trimming costs by 3%, and the Company included those savings in the projected cost of the Surge program.

Q. Are there any additional benefits to treating the right-of-way with herbicides?

A. Yes. Because grasses and shrubs are not affected by the herbicide treatment, the area will become a habitat for pollinators, birds, and small mammals. The treatment will also target invasive plant species, limiting their spread.

Measuring Progress

Q. How will the Company evaluate the results of the tree trimming Surge?

A. The Company will provide an annual report detailing the circuit performance. Additionally, the Company proposes to submit a Tree Trimming Effectiveness Report in 2022 to the Commission.

Q. How will circuit performance be measured in this annual report?

A. The Company will provide an annual report detailing the outage and non-outage events for the average of the three-years prior to the study period compared to the year after trimming for distribution circuits trimmed as part of the ETTP and those not trimmed.

Q. How will the Company evaluate the results of the tree trimming Surge in 2022?

A. The Tree Trimming Effectiveness Report, which will be filed in 2022, will provide an overview of the Surge and the benefits customers have received. This evaluation

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will be based upon data from five years of trimming circuits as part of the ETTP in 2016 through 2020, as shown in Table 15. This will provide five years of historical circuit performance on the ETTP compared to the remainder of the system.

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Three-year Average Pre-trim Performance			Year of Trim	Post Trim Year 1	Post Trim Year 2	Post Trim Year 3	Post Trim Year 4	Post Trim Year 5	ETTP Effectiveness Report
	Three-year Average Pre-trim Performance			Year of Trim	Post Trim Year 1	Post Trim Year 2	Post Trim Year 3	Post Trim Year 4	
		Three-year Average Pre-trim Performance			Year of Trim	Post Trim Year 1	Post Trim Year 2	Post Trim Year 3	
			Three-year Average Pre-trim Performance			Year of Trim	Post Trim Year 1	Post Trim Year 2	
				Three-year Average Pre-trim Performance			Year of Trim	Post Trim Year 1	

TABLE 15 – Illustrative Data Detail for Effectiveness Report

Conclusion

Q. Do you recommend this investment the tree trimming program?

A. Yes. The tree trimming program is the most impactful and important program in the Company's long-term investment strategy. The program will significantly decrease system risk (specifically reduced wire downs), increase reliability (fewer and shorter outages), and decrease reactive trouble costs. The tree trimming program as proposed is required to provide safe, reliable and affordable electricity to the Company's customers. Without the incremental Surge investment, the distribution system will continue to degrade, resulting in higher risks and lower reliability. The

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Company believes this program is right for our customers. The Company is requesting the regulatory asset treatment of the Surge costs with the intention to securitizing the regulatory asset in order to execute the program in a way that makes it affordable for customers.

Q. In your opinion, are these expenses reasonable?

A. Yes, they are. I base my opinion on analysis of past expenses, and the projected requirements for labor and materials to conduct the necessary tree trimming.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

REVISED

REBUTTAL TESTIMONY

OF

HEATHER D. RIVARD

DTE ELECTRIC COMPANY
REVISED REBUTTAL TESTIMONY OF HEATHER D. RIVARD

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Q. What is your name, business address and by whom are you employed?

A. Heather D. Rivard, Senior Vice President of Distribution Operations, One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, (LLC), a subsidiary of DTE Energy.

Q. Did you file direct testimony in this proceeding on behalf of DTE Electric Company (DTE Electric)?

A. Yes, I did.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to discuss the impact of MPSC Staff's alternative tree trimming proposal put forth by Staff Witness Evans; to explain why the tree trim Surge performance conditions requested by Attorney General (AG) Witness Coppola are not appropriate for Surge approval; and to rebut inaccuracies in Michigan Environmental Council, Natural Resources Defense Council and Sierra Club's (MEC) Witness Jester's testimony regarding the historic performance and spend of DTE's tree trimming program.

Q. What is Staff Witness Evans' position regarding the Company's Tree Trim Surge program?

A. Staff Witness Evans supports some aspects of the Surge but not others. Witness Evans supports the goal of achieving a five-year tree trimming cycle for distribution circuits, and also supports the Company's current three-year cycle for sub-transmission circuits. Witness Evans also agrees that there is a backlog of overgrown vegetation that must be addressed for the Company to achieve a five-year cycle, and

that removing this backlog will require additional funding over a period of time. However, Staff believes that deferring and amortizing the costs is not in the best financial interest of ratepayers. Staff believes that placing the Surge costs into a regulatory asset and amortizing them will burden future ratepayers with costs that are more appropriately O&M expense that should be paid as the costs are incurred.

Q What is Staff Witness Evans' proposal?

A. First, Staff Witness Evans recommends the Commission not approve the regulatory asset for the Tree Trim Surge, which means disallowing the $7,053,000 revenue requirement associated with the Surge. At the same time, Witness Evans recommends that the Commission should increase tree trim expense during the test year from $95,092,000 to $108,099,000. Second, for years following the test year, the Company could request increases in spending on tree trimming until the backlog is eliminated and the five-year cycle is achieved, then drop the O&M amount to its forecasted amount shown in Exhibit A-22, Schedule L1 Revised.

Q. What is DTE Electric's position regarding Witness Evans' proposal to reject the Surge funding and, instead, fund additional tree trimming needs through regular rate cases with consistent increases in tree trim funding?

A. The Company is encouraged that Staff recognizes the scope of funding needed for the tree trim program and is supportive of DTE Electric's efforts to move the program to a sustainable 5-year trim cycle for distribution wires. The proposal Witness Evans has put forth appears to provide funding to get the Company back on cycle over a longer time period, 8 years 4 months vs. the 7 year period under DTE Electric's Surge

proposal. **CHART 1** shows the annual funding profile of DTE's proposed Surge plan as compared to the proposed MPSC Staff plan.

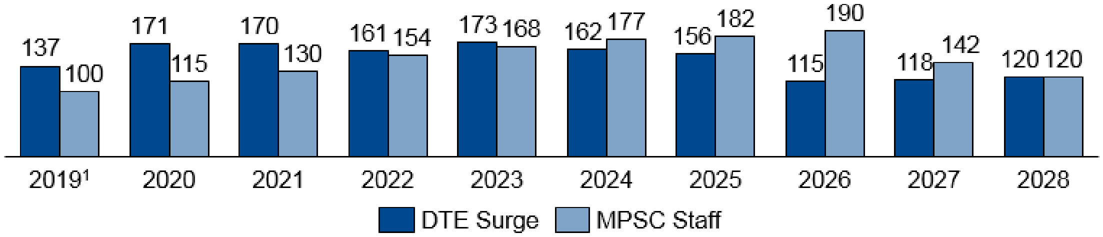

CHART 1 – Annual Spend for DTE Surge Plan vs. MPSC Staff Plan ($M)

Although Staff Witness Evans' plan does appear to provide the required funding to move the Company back to a five-year trim cycle, DTE Electric believes that the Surge program should be approved because it provides additional customer benefits:

1) The Surge plan will allow the Company to more quickly reduce the tree trim backlog miles resulting in increased reliability and cost savings from reduced trouble and storm events (seven years versus the more than eight years proposed by Staff).
2) The Company's Surge plan provides smaller near-term rate increases compared to Witness Evans' proposal because it defers and spreads out Surge expenses over a 14-year securitization period. This allows the Company to align rate increases related to Surge spending with future customer benefits and allows the Company to more effectively manage customer rate affordability. The Company understands that deferral of O&M charges is atypical but believes that it is reasonable in this situation because the benefits of the Surge program, detailed on pages 24-29 my initial testimony and in exhibit A-22, extend into the future benefiting DTE Electric customers in perpetuity.

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3) Approval of the Company's proposed Surge plan in this case will allow for funding certainty that will help the Company enter into long-term contracts with tree trimming vendors. Long-term contracts are expected to provide more competitive pricing and greater tree trimmer labor stability as the Company continues to increase work volumes. Because tree trimmers are in high demand across the country, failure to secure long-term contracts could make it difficult to obtain enough workers to complete the required work.

Q. In the event that the Commission considers Witness Evans' proposal and requires the Company seek annual rate recovery for tree trimming expenses, will additional funding be required to achieve the goals of the Surge?

A. Yes. If the Commission chooses to reject the Surge plan and accept the Staff's recommendation to expense the tree trim costs, the Company requests funding for the Tree Trim Program in the amount of $137.5M O&M for the test year May 1, 2019 through April 30, 2020. Test year funding of $137.5M will enable the Company to recover $119.6M in tree trim expenses the 2019 calendar year[1], $17.9M less than the Company's requested Surge funding in the 2019 calendar year. The Company believes that this would be a reasonable compromise between Witness Evans' funding profile and the Company's proposed Surge program. The $137.5M request will help DTE Electric accelerate the needed tree trimming work by providing short term funding certainty needed to secure additional tree trim labor.

Q. AG Witness Coppola suggests that the Commission require DTE achieve outage reduction targets and if targets are not met the Company would lose the ability

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[1] $119.6 is derived from approved tree trim funding of $83.7M prorated for the first four months of 2019 plus $137.5M prorated for the last eight months of 2019

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to recover some or all deferral recovery in the calendar year. Do you agree with AG Witness Coppola's Surge conditions?

A. No, I do not believe AG Witness Coppola's conditions are fair or warranted.

Q. Why are Mr. Coppola's suggested conditions unwarranted?

A. First, the Company is only requesting a return of Surge dollars that are deferred on a temporary basis. As discussed by Company Witness Mr. Solomon on pages 21 through 25 of his direct testimony, the Company intends to seek securitization of the regulatory asset once the balance reaches approximately $100 million. This is anticipated to occur during the fourth quarter of 2020. Securitization provides no return for shareholders; it recovers only the debt costs. Therefore, there is no meaningful financial return to shareholders from the Surge proposal.

Second, Witness Coppola proposes to measure DTE Electric through yearly outage reduction targets but does not account for weather based volatility. Large weather events, such as the March 2017 wind storm, can cause large swings in outage event volume from one year to the next. Under Witness Coppola's proposed conditions, a bad storm event could result in a significant financial loss to the Company despite an overall positive downward multiyear trend in outage volumes.

Additionally, the Company is unable to fully predict the tree trim labor market. The proposed Surge spend profile assumes that the Company is going to be able to attract a significant volume of tree trimmers to our service territory in the short term and grow the tree trimmer work force locally in the long term. If the Company is unable to fully ramp up additional tree trimmers due to events outside of its control (for

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example, recent California wildfires have caused utilities in that state to significantly increase tree trim budgets resulting in unprecedented demand for tree trimmers in an already constrained national labor market), it may need to shift some of the Surge spend from the early years to years 4-7. This adjustment would directly impact the number of outage reductions expected and cause the Company to miss targets for reasons outside of its control.

While the Company does not believe Witness Coppola's conditions are appropriate, the Company will be transparent with Surge program results and will make regular reports to the Commission that include Surge tracking metrics and progress. Additionally, the Company will work with the Commission and Staff to make appropriate modifications to the Surge program as actual results dictate.

Q. MEC Witness Jester states that the Company's historical failure to execute tree-trimming on the appropriate cycle has been costly to the Company in higher costs of slower-cycle tree trimming and reactive maintenance which have been reflected in customer rates. Do you agree with this statement?

A. No, I do not agree. MEC Witness Jester does not accurately identify what has resulted in the current tree conditions. The Company maintained a five-year tree trimming cycle through the end of 2013 while maintaining what were considered industry standard specifications. In 2014, through our continuous improvement efforts, the Company determined that the old tree trimming specification was not yielding the desired results as more than two thirds of the outage minutes were found to be caused by trees. Thus, the Company changed its specification and created the Enhanced Tree Trimming Program (ETTP) program to reduce tree related outage events. Trimming

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to the new reliability based "enhanced" trim specification required more trimming work than the old specification and was more expensive. Not maintaining an appropriate tree trim cycle does increase customer outages and trimming costs but Witness Jester fails to acknowledge that the majority of increased customer cost related to tree trimming is driven by increased trimming costs from more stringent ETTP trim specifications and high outage volume related to the Company's old specifications.

Q. MEC Witness Jester also asked that the Commission reduce the amount of the Surge regulatory asset by an amount that reflects the present value of the Company's historical failure to trim trees on a reasonable schedule. Is this penalty reasonable?

A. No, it is not. As discussed above, DTE Electric has historically maintained a five-year tree trim cycle. **TABLE 1** indicates that the Company has consistently spent the tree trimming dollars allocated to it in past rate cases. Since 2009, the Company has spent $19 Million more than approved amounts in rate cases. This spend pattern clearly demonstrates that the Company has been, and continues to be, focused on trimming trees to maximize the reliability customer reliability.

	Rate Case Approved Spend[2]	**Actual Spend**	**Over / (Under) Spend**
2009	$ 49.6	$ 49.0	$ (0.6)
2010	$ 47.0	$ 47.0	$ -
2011	$ 49.5	$ 50.3	$ 0.8

[2]Calendar year values were calculated using weighted averages of approved funding based on rate case timing

2012	$	50.7	$	53.1	$	2.4
2013	$	50.7	$	56.9	$	6.2
2014[3]	$	50.7	$	42.3	$	(8.4)
2015	$	58.2	$	64.6	$	6.4
2016	$	69.7	$	74.2	$	4.5
2017	$	76.6	$	84.3	$	7.7

TABLE 1 – 2009-2018 Approved Tree Trim Rate Case Funding vs. Actual Spend

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

[3] Low expenditures due to high volume of storm activity during 2014 and anticipation of new ETTP standards

JUDGE WALLACE: Mr. King.

CROSS-EXAMINATION

BY MR. KING:

Q Good afternoon, Ms. Rivard.

A Good afternoon.

Q Joel King with the Attorney General' office. I don't think we've met before.

A No.

Q Ms. Rivard, your direct and rebuttal testimony mainly address tree trimming expenses and a proposed program to accelerate spending in this area over the next seven years; is that correct?

A Correct.

Q Can you please go to page 4 of your rebuttal testimony.

A I'm there.

Q Now, beginning on line 23, and then kind of through the next couple pages through line 12 on page 6, you disagree with Mr. Coppola's proposal that the Commission should hold the Company accountable for tree trimming expenditures by establishing targets for tree-related outages, correct?

A Yes.

Q And your view is the accountability targets and penalties that Mr. Coppola proposed are not fair or warranted, correct?

A Correct.
Q Now, on page 5 of your rebuttal, beginning on line 6, you state that one of the reasons that the accountability requirements are not warranted is because the Company plans to securitize some or all of the expenditures. Now, as I understand, securitization of these costs is anticipated but not yet assured, correct?
A Correct.
Q And if the securitization does not occur or until it occurs, the Company would return -- would earn a return on the expenditures included in the deferred regulatory asset; is that correct?
A I believe so, but I think Witness Slater would be the best person to answer the question about what the return would be on the costs.
Q But to your knowledge, that's correct, that until it was securitized, that the Company would earn a return on those expenditures?
A Yes.
Q Now, irrespective of whether securitization occurs, the Company expects to recover 100 percent of the 410 million of surge program expenditures; is that correct?
A Yes.
Q And under your proposal, this full cost recovery would occur regardless of the amount of reduction in tree-

related outages that the Company would achieve during or after the expenditure surge, correct?

A Yes. Yes. But we are also proposing that we do a regular review with the Commission Staff on the success of the program and deliverance of the savings.

Q O.K. But aside from that review, regardless of, you know, the amount of outages achieved, you would expect to recover the full amount of expenditures?

A Yes. The only reason for my clarification is that if the savings that we expect to see don't come to fruition, we would be in regular discussion with the Commission and we wouldn't continue to, propose to continue the program if it wasn't having the results that we expected. So I don't see us spending all of that money and having none of the savings because we would have had the conversation with the Commission prior to that occurring.

Q All right. But what do you anticipate regular discussion means in that context?

A In my rebuttal testimony as well as on page I believe it's 48 of my direct testimony, I proposed various methods for measuring the progress of the program and working with the Commission as well as the Staff in both discussions as well as the filing of annual reports.

Q And would those discussions include other parties, such as the Attorney General?

A I am not sure how those proceedings would work. I think that the Commission could certainly issue orders or processes to allow that to happen.

Q O.K. So as far as these discussions go, your idea here is kind of a preliminary one without much substance in how that would work?

MS. HAYDEN: I'm going to object to the -- you're assuming facts that aren't in evidence. There's actually testimony -- there's an annual -- she already discussed that there's an annual report that's going to be filed, so I think it's misconstruing Ms. Rivard's testimony, these are not developed ideas.

MR. KING: I'm sorry. So you said these are not developed, or I'm misconstruing them as not developed?

MS. HAYDEN: Ms. Rivard pointed to her testimony that talks about the things they plan to report, so if you could rephrase the question. My objection would also be to the form of the question.

JUDGE WALLACE: Can you rephrase?

MR. KING: Sure.

Q (By Mr. King): Yeah. I guess I just, I was trying to get some more clarification from your perspective on how these discussions would play out, you know, in the context of an annual report and in the context of the

evaluation of the program.

A So according to my testimony on pages 48 and 49, we would file an annual report, and in that annual report would detail the performance in terms of event production and in terms of the overall effectiveness of the program. It also proposes that we would file a more comprehensive tree trimming effectiveness report in 2022 to the Commission. And I'm assuming that these reports would be filed as part of a record or docket that others would be allowed to comment on, but I'm not sure how those proceedings work.

Q O.K. Are you proposing any payback by the Company or penalties on the Company if it does not achieve a reduction in tree-related outages?

A No.

Q On page 5 of your rebuttal, I think that's where we were, beginning on line 14, you state that Mr. Coppola -- oh, sorry.

A Yeah, I'm here.

Q All right. You state that Mr. Coppola does not account for weather-based volatility, correct?

A Correct.

Q And the Company does have the ability to calculate and report weather normalized outages or weather normalized outage reduction results, correct?

A Over a period of time, typically three to five years; it's hard to normalize on a one-year basis.

Q So as I understand it, just generally, the objective of this enhanced tree trimming program and the surge that you've recommended is to widen the tree-free corridor around power lines and achieve this five-year trimming cycle that you discuss, correct?

A Yes. It's both widening of the corridor as well as greater removal of trees within the corridor.

Q And so this in time should lessen or prevent power outages caused by tree damage during major storms?

A Yes. In fact, from our experience so far, we have seen significant reductions in the number of outages on circuits that have been trimmed to this specification, both in the short term and in the long run, as well as our benchmarking with other utilities supports those reductions.

Q Do you know what -- I mean you said -- so are you just saying that you've seen really good results on the circuits that you have trimmed? Do know what percentage of your lines you've done that to, approximately, or how much?

A Yes, I believe there is an exhibit in my testimony, but roughly I would say we've trimmed close to half of our miles to the new specification, subject to check and

verification.
Q Sure. Can you go to line 21 here on page 5.
A Of the rebuttal?
Q Yes, of your rebuttal.
A Yes, I'm here.
Q So beginning here and going on to line 6, the next page, you state that the Company is unable to predict the tree-trim labor markets and the availability of tree trimmers, correct?
A Correct.
Q And then you go on to state that the availability of tree trimmers or the nonavailability of tree trimmers may cause the Company to miss targets, and that's something that's outside of the Company's control, correct?
A Yes, that could happen.
Q But in your opinion, this concern is not something that should prevent the Commission from approving the Company's proposal?
A Correct. We believe that we are going to be able to secure the necessary resources to complete our surge plan as we put forth.
Q If recruiting tree trimmers becomes a significant issue for the Company, the Company could ask for an allowance when the Commission evaluates the Company's performance; is that correct?

A I'm not sure if I understand what you mean by an allowance or what that would look like.
Q I guess some sort of adjustment perhaps when you, you know, when you're filing the annual report or when you're discussing progress with the Commission; does that clear anything up or anything?
A What was the question again?
Q I guess I was just -- so if this becomes a significant issue where the tree trimming market isn't what you expect for whatever reason, is that something that would be discussed with the Commission during those annual updates?
A Yes. If that became an issue, it would be part of our annual report, and we talk to the Commission Staff regularly enough that they would hear about it as it was transpiring as well.
Q Can you please turn to page 6 of your rebuttal.
A Yep, I'm there.
Q So lines 8 to 12, which is basically what we've been discussing all along here, right, in this section you're simply proposing that the Company file these reports with metrics, make certain adjustments along the way with, you know, give and take from the Commission; is that correct?
A Yes. Basically lines 8 through 12 are summarizing what was on page 48 of my original direct testimony; and as I

mentioned before, if we were not seeing the results that we expected to see from the tree trimming program, the Company would not continue to propose to keep going with the program as outlined either because we're doing the program in order to achieve improved reliability, and if that improved reliability doesn't play out, it would be part of the discussions with the Commission to come up with a new plan. So far all results indicate that it is going to play out at least as well as we've laid out in the testimony, if not better.
Q But as you mentioned, your proposal would not include any kind of refund or penalty to the Company if this does not play out the way the Company anticipates?
A No. And there's no -- with the deferral and securitization, there's no financial benefit anticipated to the Company either, the costs are a direct passthrough.
Q Thank you.
MR. KING: I have no further questions, your Honor.
JUDGE WALLACE: Thank you. Mr. Keskey.
CROSS-EXAMINATION
BY MR. KESKEY:
Q Good afternoon, Ms. Rivard.
A Good afternoon.

Q Tree trimming expense has been an expense in every year and every rate case; is that correct?
A To the best of my knowledge. So this is the first time I'm the witness for tree trimming.
Q And is it correct that the Commission in its past rate orders has always provided a rate allowance for tree trimming?
A I believe that they have provided the rate allowance in previous rate cases in line with our program and our specifications at that time.
Q The amount of expenditure that the Company actually incurs for tree trimming in any given year is a management decision, is it not?
A To some extent, it is, but we are also -- we also have tree trim expense that is reactive in nature and is part of many of these numbers that is in response to trouble and storm events on the system, and so to the extent that we have to do tree work in order to restore power, I wouldn't necessarily say that's directly within the Company's control.
Q How would you define reactive expenditures?
A Reactive expenditures are when someone loses power or has some sort of trouble event, such as power quality issue or tree on a wire, flickering lights, where a tree has caused interference and we as a Company have to go out

and remove the tree and fix the system.
Q And would storm and bad weather be another example of reactive expenditures?
A That is a primary example of reactive expenditures.
Q And is it correct that the Company usually applies to the Commission for amortization of storm damage expenses in separate cases when that occurs when there are outages due to bad weather?
A I'm not sure I understand the question.
Q When you have a significant storm and widespread customer outages and you incur unforeseeable large expenses for addressing the storm damage, is it correct that the Company normally applies for a storm damage case?
A Not to my knowledge. I believe all of our storm expenditures have been part of our normal rate cases.
Q Do you amortize storm damage over a period of years when they occur at higher than expected unforeseeable storm damage costs?
A Not that I'm aware of, no.
Q Now, the Company itself has the management prerogative as to how and when and how much to spend on tree trimming or addressing outages; is that right?
A Could you repeat the question?
Q The Company has management prerogative to operate its tree trimming program and to determine how much to spend

for tree trimming and for addressing outages?

A I think there are two parts to your question. As far as tree trimming is concerned, that the Company does have the prerogative, and the Company has consistently spent either equal to or more than the authorized amount on tree trimming, which is outlined in one of my discovery question responses. And when it comes to storm and trouble, I don't think I agree that it's the Company's discretion, unless there's a suggestion that we would leave people without power. We have to respond when someone is out of power and restore during storm or trouble, so those are reactive expenses that I don't think the Company has discretion on whether to respond to or not.

Q Well, the point here is that the Michigan Public Service Commission and the ratepayers do not exercise any prerogatives over how to run or administer the tree trimming program or how much is spent in any given year; is that right?

A That is right.

Q Now, tree trimming expenses are only one of many elements of the overall expense categorized as operation and maintenance expense; is that correct?

A Yes.

Q So the Company also has some prerogative, management

prerogative over how much to spend for any of the other elements of operation and maintenance expense besides tree trimming, correct?

A Yes.

Q And for example, if you have to spend more on tree trimming in a given year than what was assumed in rates, the Company has prerogative to offset that by spending less on some other category of operation and maintenance expense or to cut back on another expense or to defer another expense; is that an option?

A I believe that that is the Company's prerogative. Of course, that would have impacts of a different kind depending on what you reduced.

Q Have you compared the overall total operation and maintenance expense that the Company has incurred in contrast to the amount of O&M expense assumed in rates to assert that there's been a shortage in the amount that you received in rates for operation and maintenance expense overall?

MS. HAYDEN: Object to the form of the question. I think there were two or three questions in there.

JUDGE WALLACE: Could you rephrase, Mr. Keskey?

Q (By Mr. Keskey): Well, if we look at total operation and

maintenance expense included in the Company's rate request and compared that to what the Commission granted for the overall total operation and maintenance expense, have you presented an analysis that the Company received a shortage in rates for that category, namely operation and maintenance expense overall?
A There is nothing about that in my specific testimony or exhibits that I'm sponsoring, if I understand the question correctly.
Q So you're not claiming that in instances where the Company may have spent more for tree trimming in a given year than was assumed in rates, that that resulted in a shortage in earning your authorized common equity return?
A I'm not sure how it would tie directly to our authorized rate of return, but in my schedule, which is one of my -- let me make sure I call it the right thing -- Schedule C5.6, I do outline what the Company spent on tree trimming in 2017, and we did spend more than what was authorized in the rate case associated with that timeframe.
Q Well, I think you may refer to that on page 6 of your direct testimony, lines 21 through 24?
A Yes.
Q Does that match the exhibit that you just referenced?
A Yes, it does. This talks about comparing it to the test

year, and the exhibit is using a calendar year, but I believe it's generally the same thing, yes.
Q Well, if you take a look at the statement you make on that page 6 of your direct, you're comparing what the Company spent on tree trimming in the entire calendar year 2017 compared to what was granted in U-18014 for only the part of the calendar year through July 31, 2017, right?
A Yes, and starting August 1 of 2016, the full test year.
Q But you would have received in rates after July 31 in 2017 amounts for tree trimming, would you have not?
A Yes.
Q And so your statement on direct testimony page 6 is really comparing apples to oranges, you're not using comparable time periods?
A That would be correct. If the question is whether we've spent what we've been authorized, on page 7 of my rebuttal there's a test -- there's a table that outlines all of the years from 2009 to 2017 and how our approved spend compares to our actual spend.
Q Now, in your case you're asserting that there is a backlog in tree trimming that should be addressed; is that right?
A Yes.
Q And what has been the cause for the backlog?

A The backlog that we refer to in my testimony -- let me go to the right page -- is basically a backlog related to what has been trimmed to the new enhanced specification and what was trimmed to a prior specification. The definition of backlog is on, starts on page 16 of my testimony in case there's any confusion about that. But it refers to circuits that have yet to be trimmed to the new enhanced specifications.
Q Well, is the backlog caused by a change in the standards when you compare past rate cases to this rate case?
A Yes, by definition, because the backlog here is referring to miles not trimmed to the new specification.
Q And the new specifications commence when?
A It started -- I believe it is on page 5 of my direct testimony. The new specification started in Case U-18014 and also in Case U-18255.
Q Now, are you asserting that the backlog is caused by some action or inaction of the Public Service Commission?
A No.
Q Is the backlog caused at least in part by management decisions?
A No.
Q And therefore without repeating, but repeating, what is the cause of the backlog; does it change the specifications or standards?

A The amount of funding for tree trimming in addition to the new specifications does not allow for the trimming of enough miles per year to maintain a five-year cycle.
Q Now, is it -- would it be correct that the Commission -- well, let me restate the question.
Would it be correct that one option to address the backlog would be for the Commission to grant a higher amount in rates for tree trimming for the test year and then going forward?
A Yes.
Q And so an alternative to any kind of future securitization proposal or filing would be the Commission addressing it in rate orders with additional funding in rates?
A Yes.
Q As part of recognizing higher amounts in rates for tree trimming, would the Company, to your knowledge, consider adopting a two-way tracker to ensure that the actual spending at least matches the amount recognized in rates?
A I believe that the Company would consider a two-way tracker related to tree trimming expenses.
Q If in fact the Commission were to grant recognition in rates for tree trimming expense of enhanced amounts in rates, that also could be an alternative to your proposal to have a deferred accounting and a regulatory asset for

that expense; would that be correct?
A Yes, that would be correct. The concern is that the costs are front-loaded over a shorter period, the saving span multiple years, and so the Company's concern is one of rate affordability for our customers, which is why we proposed the deferral and securitization.
Q However, rate affordability depends on the overall rates that are charged, which can be affected by a number of other components in the ratemaking formula which may absorb all or part of that increase for tree trimming, correct?
MS. HAYDEN: Object. It calls for speculation.
JUDGE WALLACE: Sustained.
Q (By Mr. Keskey): Well, tree trimming is not a standalone expense, is it, in setting rates?
A No. Although it is one of the largest expenses that we have.
Q And there are other large expenses, like capital costs?
A Yes.
Q Capital structure ratios?
A I'm not familiar with those, those numbers.
Q PSCR costs --
A Yes.
Q -- are large?

A Yes.
Q Wage costs?
A Yes.
Q So tree trimming expense in and of itself does not necessarily equate to bottom-line affordability as to ratepayers, it depends on a number of factors, correct?
MS. HAYDEN: Again, same objection. Calls for speculation.
JUDGE WALLACE: Sustained.
MR. KESKEY: I think I laid the foundation, your Honor, to that question.
JUDGE WALLACE: No, I'm sustaining the question. I'm not sure where you're going with this. It all seems to be true, tree trimming is not the only expense. That, I think we've established.
MR. KESKEY: I appreciate that finding, your Honor.
JUDGE WALLACE: There might be a better witness to go over this with, at least from the accounting standpoint and the expense standpoint. I don't know.
Q (By Mr. Keskey): Is there another witness that you would recommend on this, Ms. Rivard?
A To answer the question about the --
Q Overall impact on ratepayers or affordability in the

total scheme?
A I think Company Witness Uzenski or Solomon.
Q Would it be correct that there's a number of factors that can cause the amount of expense that the Company will actually incur for tree trimming in any given year or test year, and let me give you some examples; weather could affect how much you have to spend for tree trimming?
A Yes.
Q And lack of adequate resources or vendors that can do the function in any given year?
A Yes. Although that's part of the reason for our surge proposal is the desire to lock down resources and longer term contracts to avoid that.
Q Now, the obtaining of greater efficiencies or planning in tree trimming function, that can save dollars compared to what you might project or what you might actually spend?
A Yes.
Q Time necessary to ramp up the program to address any backlog or to get onto a five-year cycle?
A No. I believe we've already anticipated that in our plans.
Q When you talk about the Company's plan to address the backlog and the getting on a five-year cycle, is that -- has that plan been implemented at this time?

A We are in negotiations with our contractors right now to make sure we have resources on property January 1 to start with the surge program.
Q In your analysis of tree trimming functions and expenses, do you consider alternatives in some instances, like, for example, burying electric lines where it's economic to avoid future outages?
A We do. We have for quite some time and will continue to look for alternatives where they make sense. So far the notion of burying lines to avoid tree trimming hasn't proven to be a successful alternative because of the cost of putting things underground, but also because you typically have to remove all the trees anyways in order to put the lines underground or you destroy the root system.
Q Do you know of any instance where you've determined that it was more cost effective to install or bury electric lines in certain neighborhoods due to frequent outages than just the --
A None that I'm --
Q -- situation of trees and right-of-way and so forth?
A None that I am aware of.
Q Now, obviously the Company has not filed a securitization case to go in that direction as you have discussed in your testimony, correct?

A Correct.
Q And you would indicate that the Company would propose to defer any expenses over what is assumed in rates as a regulatory asset until you got approximately $100 million there in that account and then you would seek to securitize; is that correct?
A Yes, that is referenced in my testimony or rebuttal, but Witness Solomon is the better person to talk to the securitization numbers and timing.
Q Is Witness Solomon the person to testify regarding how your $66 asserted savings is calculated?
A That would be the person who also was part of Exhibit A-22, pages 3 through 6, Mr. Slater, that is where the NPV is calculated.
Q And what's the discount rate you realized for that calculation?
A I don't remember off the top of my head, but Witness Slater would know the number.
Q And approximately what year would such a securitization application be filed?
A I am not -- I am not sure.
Q That's one of the unknowns about securitization; would that be correct?
A Yes, although I believe the testimony as you've referenced talks about getting to a balance of $100

million, which looks like it occurs in 2020 if I'm reading the exhibit correctly, but Witness Slater would be better to answer that.
Q One of the unknowns about that estimate would be depending on what the Commission approves for tree trimming in this case?
A Correct.
Q Would it be correct that this is the first case in which Consumers Energy has suggested securitization as an option relative to tree trimming?
A You said Consumers Energy; did you mean DTE Energy or --
Q I'm sorry. I just got out of a Consumers Energy --
A That's O.K. I thought maybe you were asking me about their case.
Q Well, no, I'm referring to DTE.
A O.K. Could you ask the question again? Is it the first year that we asked -- first time we asked for securitization?
Q The first time you've proposed a securitization option as to address tree trimming expenses.
A Yes, to the best of my knowledge, it is.
MR. KESKEY: I have no other questions, your Honor.
JUDGE WALLACE: Thank you, Mr. Keskey.
I just have a couple, I'm just trying to

wrap my head around the way that this would work. So there's like a base O&M tree trimming amount in this case?

THE WITNESS: Yes.

JUDGE WALLACE: And then anything in excess of that which is associated with this tree trimming surge would be a regulatory asset --

THE WITNESS: Yes.

JUDGE WALLACE: -- until the reg asset balance achieves $100 million or something, and then it would be securitized?

THE WITNESS: Correct.

JUDGE WALLACE: O.K. So if the O&M expense for tree trimming was, say, set at $100 million and the first year you spent 110 million, $10 million would be in -- that would be a reg asset?

THE WITNESS: Correct.

JUDGE WALLACE: So what if in year two you only spent $90 million, assuming you didn't come in for a rate case; like do you know what I mean, would the reg asset balance stay at $10 million or would it --

THE WITNESS: I don't know the answer.

JUDGE WALLACE: I'm just kind of thinking about PERC, but you don't know how that works, but that would be how that -- like here's, say, $5 million for

this nuclear stuff, and if you spend more, then it's a regulatory asset, you know, and those are very uneven expenses, and then if the next year you only spent 3 million, then the regulatory asset balance would be reduced.

THE WITNESS: Right.

JUDGE WALLACE: This doesn't work that way?

THE WITNESS: Yeah, I am not sure. I do know that --

JUDGE WALLACE: That's fine.

THE WITNESS: -- that in our exhibit, we're proposing -- and I know anything could happen, but we're proposing to get to spend levels that are close to 170 million a year, so I don't see a year where we would spend less than the base amount of 95 million, but I can't predict the future. So I think maybe Witness Slater could speak better to how, or Solomon could speak better to how it would work if it was an underspend.

JUDGE WALLACE: All right. So you're proposing something like 95 million for the O&M, and then in excess of that to get caught up on the backlog and so forth, which is a reg asset, then it's securitized at $100 million, and then $100 million of --

THE WITNESS: Yes, yes.

JUDGE WALLACE: O.K. All right.

THE WITNESS: And all of the year-by-year difference between the base and the proposed surge is what's laid out in Exhibit A-22, it varies by year, the amount.

JUDGE WALLACE: All right. Ms. Hayden, do you have any redirect?

MS. HAYDEN: Can I just have a very short recess, no more than five minutes?

JUDGE WALLACE: Sure.

(At 2:49 p.m., there was a brief in-place recess.)

MS. HAYDEN: Your Honor, I don't have any redirect, but I would like to make a clarification to the record on Ms. Rivard's direct exam. When I mentioned Exhibit A-13 Schedule C5.6, I neglected to note that she only sponsors one page of that exhibit, and that's page 3 of 3, just so the record is clear on that.

JUDGE WALLACE: I'm sorry, could you repeat that?

MS. HAYDEN: Exhibit A-13 Schedule C5.6 consists of three pages, and the first -- I'm sorry -- the first page is cosponsored by Ms. Rivard and the third page is sponsored by Ms. Rivard, so there's a page in there that is sponsored by Mr. Bruzzano, I just wanted to note that for the record. It's clear when you look at

the exhibit, but I neglected to put that in.

JUDGE WALLACE: All right. If there's nothing more for Ms. Rivard, you are excused.

THE WITNESS: Thank you.

(The witness was excused.)

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JUDGE WALLACE: Can we go off the record for a second.

(A brief discussion was held off the record.)

JUDGE WALLACE: All right. So the next witness we have is Mr. Arnold. MEC has cross for him. Does anyone else have cross for Mr. Arnold? Just MEC. All right.

MR. FISK: Your Honor, could we take a five -- could we take a brief break?

JUDGE WALLACE: Pardon me?

MR. FISK: Could we take a two-minute break?

JUDGE WALLACE: Sure, absolutely. Off the record for a couple minutes. Why don't we go ahead and take ten minutes now because we're in between witnesses.)

(At 2:54 p.m., there was a ten-minute recess.)

(Document was marked for identification by the Court Reporter as Exhibit A-29.)

JUDGE WALLACE: We're back on the record in Case No. U-20162, DTE Electric Company rate case. And we are now going to hear from Mr. Arnold. And Mr. Christinidis, would you like to proceed?

MR. CHRISTINIDIS: Thank you, your Honor.

- - -

D E R E K M. A R N O L D

was called as a witness on behalf of DTE Electric Company and, having been duly sworn to testify the truth, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. CHRISTINIDIS:

Q Can you state your name and business address for the record, please.

A Derek Arnold, 411 South Main Street, Ann Arbor, Michigan 48104.

Q And did you cause to be filed with the Commission a document entitled the Qualifications and Direct Testimony of Derek M. Arnold, consisting of a cover sheet and ten pages of questions and answers?

A Yes, I did.

Q Do you have any changes to make to your direct testimony?

A No, I do not.

Q Is that then the direct testimony you're adopting today on the stand?

A Yes.
Q And you're also sponsoring an exhibit and several schedules associated with your direct testimony, correct?
A That is correct.
Q And that exhibit and schedules are Exhibit A-29 Schedule S1 consisting of one page, Schedule S2 consisting of one page, and also Schedule S3 consisting of one page, correct?
A Yes.
Q Any changes to that exhibit or schedules?
A No.
Q Are those then -- Is that then the exhibit and associated schedules you're adopting today on the stand?
A Yes.
Q It's correct, is it not, that you're also sponsoring rebuttal testimony in this case, that consists of a cover sheet and seven pages of questions and answers?
A Yes.
Q Any changes to make to your rebuttal testimony?
A No changes.
Q And it's correct that you're not sponsoring any exhibits associated with your rebuttal testimony, right?
A Correct.
MR. CHRISTINIDIS: With that, your Honor, DTE Electric would move to bind into the record the

qualifications, direct testimony, and rebuttal testimony of Derek M. Arnold, and move the admission of Exhibit A-29 Schedules S1, S2, and S3 when you believe it's appropriate that they be admitted, and tender Mr. Arnold for cross-examination.

JUDGE WALLACE: Thank you. Is there any objection to the binding in of the testimony and rebuttal testimony of Mr. Arnold, or Exhibit A-29, admission of Exhibit A-29.

Hearing none, Mr. Arnold's testimony is bound in the record and Exhibit A-29 is admitted.

(Testimony bound in.)

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate Schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

DEREK M. ARNOLD

DTE ELECTRIC COMPANY
QUALIFICATIONS OF DEREK M. ARNOLD

Line
No.

Q. What is your name, business address and by whom are you employed?

A. My name is Derek M. Arnold. My business address is 414 S. Main Street, Suite 300, Ann Arbor, Michigan 48104. I am employed by DTE Electric Company (DTE Electric or Company).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric.

Q. What is your current position with the Company?

A. I am currently the Supervisor of the Strategic Merchant Analytics Team within the Generation Optimization Department.

Q. What is your educational background?

A. I received a Bachelor of Science Degree in Mechanical Engineering from Wayne State University in 2008 and a Master of Business Administration Degree from Wayne State University in 2016.

Q. What is your work experience?

A. From 2006-2008, I worked at DTE Electric's Monroe Power Plant as an engineering co-op responsible for equipment inspections and special projects. After obtaining my Bachelor of Science degree from Wayne State University in 2008, I was employed by DTE Electric as an associate engineer in the Generation Optimization Organization. In the Generation Optimization group, I was responsible for forecasting and optimization of the Fossil Generation Power Plant fleet, including leading the fuel blending initiative.

In 2009, I joined the Fossil Generation Strategic Planning group as a principal market engineer. In this role, I was responsible for the modeling of the DTE Electric generation fleet to support corporate forecasting, fuel contracts, and regulatory filings.

In 2012 and 2013, I cross-trained as a capital and O&M financial controller at Monroe Power Plant. In this role, I was responsible for budgeting, tracking, and accounting activities at the power plant.

In 2014, I returned to the Fossil Generation Strategic Planning group to continue as a principal market engineer where I was responsible for modeling and analyzing strategies and scenarios.

In 2016, I was promoted to my current Supervisor position within the Generation Optimization Department.

Q. What are your duties and responsibilities in your current position?

A. My current responsibilities include supervising a group of engineers responsible for resource adequacy processes, modeling the DTE Electric generation fleet, optimizing financial transmission rights, procuring emission allowances, executing special studies, and advocating Company recommendations in MISO stakeholder forums.

Q. What has been your involvement in cases before the Michigan Public Service Commission (MPSC or Commission)?

A. I was the Generation Optimization witness for the 2018 Power Supply Cost Recovery (PSCR) Plan Case No. U-18403. I also provided support for the 2014 PSCR Plan Case No. U-17319, 2015 PSCR Plan Case No. U-17680, 2016 PSCR Plan Case No. U-17920, and 2017 PSCR Plan Case No. U-18143.

DTE ELECTRIC COMPANY
DIRECT TESTIMONY OF DEREK M. ARNOLD

Line No.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to establish the capacity-related generation costs, the benefit of energy and ancillary services sales from the Company's capacity resources, and the energy sales revenue net of fuel cost included in the Company's Power Supply Cost Recovery (PSCR) Factor. This information is used by Company Witness Mr. Lacey in his cost of service.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-29	S1	Projected 2018 PURPA Capacity-Related Generation Cost
A-29	S2	Projected 2018 PA295 Capacity-Related Generation Cost
A-29	S3	Projected 2018 Capacity-Related Generation Cost & Energy Sales Revenue Net of Fuel Cost

Q. Section 6w(3)(A) of Act 341 requires that the capacity charge include capacity-related generation costs in the Company's PSCR Factor, as well as other rates and surcharges. What are the capacity-related generation costs included in the Company's PSCR Factor?

A. The Company's PSCR Factor includes capacity-related generation costs associated with PURPA power purchase agreements, PA295 Company-owned renewable energy systems, PA295 renewable energy contracts, and capacity purchases.

Line No.

Q. How did the Company project the 2018 capacity-related generation costs for PURPA power purchase agreements as included in its PSCR plan filing on September 28, 2017 in Case No. U-18403?

A. The Company's PURPA contracts have three rate components; fixed, operation and maintenance (O&M), and variable. The projections for both the fixed and O&M components were included in the capacity-related generation costs. The total projected 2018 PURPA capacity-related generation cost is approximately $24.1 million as shown on Exhibit A-29, Schedule S1.

Q. What costs associated with PA295 company-owned renewable energy systems and power purchase agreements are included in the PSCR?

A. The portion of the cost of PA295 company-owned renewable energy systems that is passed through the PSCR mechanism is the lower of the Transfer Price approved for the renewable energy systems and the levelized cost of energy calculated for the renewable energy system. The portion of the cost of PA295 power purchase agreements (i.e. non-Company owned) that is passed through the PSCR mechanism is the lower of the Transfer Price approved for the power purchase agreement and the contract price of the agreement.

The Transfer Price is a proxy for the incremental non-renewable capacity and energy expense that would be passed on to the customer if the renewable energy resource was not developed. The relevant statute explains that when setting the Transfer Price, the Commission shall consider factors including, but not limited to, projected capacity, energy, maintenance, and operating costs, information filed under Section

6j of 1939 PA 3 (MCL 460.6j), and wholesale market data including, but not limited to, locational marginal pricing.

Q. How did the Company project the 2018 capacity-related generation costs for PA295 company-owned renewable energy systems and power purchase agreements?

A. The capacity-related generation cost for PA295 company-owned and non-company owned renewable energy systems and power purchase agreements is the approved Transfer Price fixed component for each specific renewable energy system. The total projected 2018 PA295 capacity-related generation cost is approximately $66.6 million as shown on Exhibit A-26, Schedule S2.

Q. How did the Company project the 2018 cost of capacity purchases?

A. The Company included the net capacity purchase costs based on forecasted expense for the calendar year 2018.

Q. How did the Company calculate the projected 2018 energy sales revenue net of projected fuel costs per Section 6w(3)(B) of Act 341?

A. Section 6w(3)(B) of Act 341 requires that the revenue, net of projected fuel costs, from energy market sales, off-system energy sales, ancillary services sales, and energy sales under unit specific bilateral contracts be subtracted from the capacity charge. To calculate the energy sales revenue net of projected fuel costs, first the revenue associated with energy sales from the Company's generation resources was determined, which is any excess generation sold into the MISO energy market after serving the Company's bundled load. I used this methodology at the direction of

Company Witness Stanczak. Next, the revenue associated with ancillary services provided by the Company's generation resources was determined. The portion of those ancillary services associated with the energy sales was then determined by multiplying by the ratio of energy sales volume to total generation volume.

Q. What is the projected revenue associated with energy sales from the Company's generation resources in 2018?

A. In the Company's 2018 PSCR Plan (U-18403), there are 2,389 GWh of projected energy market sales in 2018 with associated revenue of $88.8 million as shown on Exhibit A-29, Schedule S3, lines 11 and 12, respectively.

Q. Is the Company projecting any off-system energy sales or sales under unit specific bilateral contracts in 2018?

A. No. These values are shown as zero on Exhibit A-29, Schedule S3, lines 13 and 14.

Q. What is the projected ancillary services revenue associated with energy sales from the Company's generation resources in 2018?

A. The Company's generation resources receive revenue for providing the following ancillary services: regulation reserves, spinning reserves, and supplemental reserves (all settled via MISO's energy and ancillary services market) and reactive reserves (settled per Schedule 2 of the MISO tariff). The Company's 2018 PSCR Plan projected that Company's generation resources would generate $1.8 million of revenue associate with regulation, spinning, and supplemental reserves and $13.1 million of revenue associated with Schedule 2 reactive reserves. The portion of these ancillary services revenues associated with the energy sales from the Company's

generation resources in 2018 is determined by multiplying the total ancillary services revenue by the ratio of the energy sales volume to the total projected generation volume (2,389 GWh / 41,697 GWh), which amounts to $0.1 million for regulation, spinning, and supplemental reserves revenue as shown on Exhibit A-29, Schedule S3, line 15 and $0.8 million for reactive reserves revenue as shown on Exhibit A-29, Schedule S3, line 16.

Q. What is the total projected energy sales revenue including ancillary services in 2018?

A. The total projected energy sales revenue including ancillary services in 2018 is $89.7 million as shown on Exhibit A-29, Schedule S3, line 17.

Q. What is the projected fuel and fuel related cost required to generate the projected energy and ancillary services sales from the Company's generation resources in 2018?

A. The projected fuel and fuel related cost required to make the energy and ancillary services market sales is projected by calculating a fleet average generation fuel price and multiplying it by the energy sales volume. The fleet average generation fuel price is calculated by summing the total projected fuel, emission allowance, and chemical costs for the Company's generation fleet ($857.9 million as shown on Exhibit A-29, Schedule S3, line 24) then dividing by the total projected generation volume (41,697 GWh as shown on Exhibit A-29, Schedule S3, line 25) which results in a generation fuel price of $20.58/MWh as shown on Exhibit A-29, Schedule S3, line 26. The generation fuel price is multiplied by the projected energy market sales

Line
No.

volume to get a projected 2018 energy sales fuel cost of $49.2 million as shown on Exhibit A-29, Schedule S3, line 28.

Q. What other costs are associated with the projected energy sales described above that should be netted against the revenue?

A. MISO incurs costs when providing the following services including, but not limited to: 1) market modeling and scheduling functions; 2) market bidding support; 3) locational marginal pricing support; 4) market settlements and billing; 5) market monitoring functions; and, 6) simultaneous co-optimization for the scheduling and enabling of the least-cost, security-constrained commitment and dispatch of Generation Resources to serve Load and provide Operating Reserves in the MISO Balancing Authority Areas while also establishing a spot energy market. MISO recovers these Energy and Operating Reserve Markets Support Administrative Service Cost through a recovery adder filed as Schedule 17 in the MISO tariff. The projected Schedule 17 rate for 2018 is $0.0732/MWh, so the Schedule 17 admin fees associated with the 2,389 GWh of projected energy market sales in 2018 is $0.2 million as shown on Exhibit A-29, Schedule S3, line 30.

Q. What is the Company's projected energy sales revenue net of projected fuel costs per Section 6w(3)(B) of Act 341 for 2017?

A. The total projected 2018 energy sales revenue of $89.7 million, net of $49.2 million in fuel related costs and $0.2 million in Schedule 17 admin fees equates to $40.3 million energy sales revenue net of fuel related costs as shown on Exhibit A-29, Schedule S3, line 32. This amount was provided to Company Witness Mr. Lacey to develop his capacity related cost of service.

Line
No.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

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DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

REBUTTAL TESTIMONY

OF

DEREK M. ARNOLD

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF DEREK M. ARNOLD

Line No.

Q. What is your name, business address and by whom are you employed?

A. My name is Derek M. Arnold. My business address is 414 S. Main Street, Suite 300, Ann Arbor, Michigan 48104. I am employed by DTE Electric Company (DTE Electric or the Company).

Q. Did you file direct testimony in this proceeding on behalf of DTE Electric?

A. Yes, I did.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the capacity-related reliability need and capacity value of St. Clair Units 1, 2, 3, and 6 that MEC-NRDC-SC (MEC) Witness Allison claims is unclear (Avi Allison Direct Testimony page 7, line 1). Specifically, I will discuss capacity market fundamentals and how local resources like the Company's Tier 2 units (which include the St. Clair power plant) support MISO Zone 7 (where DTE Electric's electric service territory is located) meeting the MISO Zone 7 Local Clearing Requirement (LCR), which has both economic and reliability benefits. In addition, I respond to certain related assertions of MEC Witness Fagan.

Q. What does the LCR represent?

A. The LCR represents the amount of capacity needed within a MISO Zone in order to meet the NERC reliability standard of a one-day loss of load event every 10 years. LCRs for each MISO capacity zone are calculated annually in MISO's Loss of Load Expectation (LOLE) study and are used in the clearing of the Planning Resource Auction (PRA), a one-year, prompt capacity auction. MISO Zone 7 predominately

consists of the lower peninsula of Michigan. Zone 7's LCR varies from year-to-year based on variation in the parameters used in the calculation of the LCR.

Q. What parameters are used in the calculation of the LCR?

A. The Local Reliability Requirement (LRR) and Capacity Import Limit (CIL) are directly used to calculate the LCR. The relationship can be seen in the following equation[1]:

LCR = LRR – CIL – Non-pseudo tied exports

In recent years, there have been no non-psuedo tied exports in Zone 7 and the equation simplifies to LCR = LRR – CIL.

Q. How did MISO Zone 7 Per-Unit LRR and CIL change from Planning Year (PY) 2018/2019 to 2019/2020?

A. The MISO Zone 7 Per-Unit LRR increased from 115.3% to 117.2% of zonal coincident peak demand. The MISO Zone 7 CIL dropped from 3,785 MW to 3,211 MW.

Q. What effect does a rising Per-Unit LRR and a shrinking CIL have on the amount of local resources needed to meet the NERC reliability standard of one-day loss of load event every 10 years?

A. A higher Per-Unit LRR and lower CIL will result in a need for more local resources to meet the NERC reliability standard, holding all else constant. For example,

[1] MISO Business Practice Manual No. 011 – Resource Adequacy, p. 82. Available at https://cdn.misoenergy.org//BPM%20011%20-%20Resource%20Adequacy110405.zip.

assuming the MISO Zone 7 peak load was 21,000 MW in PY 2018/2019 and 2019/2020, the amount of local resources needed to meet the NERC reliability standard increased by roughly 1,000 MW, year-over-year, based on the ~2% increase in Per-Unit LRR and ~600 MW decrease in CIL.

Q. What would the results of the December 2017 Capacity Demonstration look like using the PY 2019/2020 MISO Zone 7 Per-Unit LRR and CIL?

A. The following table summarizes this scenario for MISO Zone 7 PY 2021-2022.

Table 1 – Planning Year 2021/2022 Forecasts

Line #	Description	Staff Report	Staff Report with PY 19/20 LRR and CIL
1	Zone 7 Peak Demand [1]	21,209	21,209
2	LRR Unforced Capacity per-unit of Peak Demand [1,2]	115.4%	117.2%
3	Local Reliability Requirement (LRR = Line 1 x Line 2)	24,475	24,857
4	Capacity Import Limit (CIL) [3]	3,785	3,211
5	Local Clearing Requirement (LCR = Line 3 - Line 4)	20,690	21,646
6	Demonstrated and Undemonstrated Resources [4]	21,910	21,910
7	Anticipated LCR Position (Line 6 - Line 5)	1,220	**264**

(1) Based on 2018 LOLE Report

(2) LRR update is based on PY 2019/20 value in 2019 LOLE Study Report

(3) Staff assumed PY 2018/19 CIL. CIL update is based on PY 2019/20 value in 2019 LOLE Study Report

(4) Based on U-18441 MPSC Staff Report and Recommendations

As seen in Table 1, applying the PY 2019/2020 MISO Zone 7 Per-Unit LRR and CIL values to the 2017 Capacity Demonstration results in a 264 MW length to the MISO Zone 7 LCR in PY 2021/2022. In other words, under this forecast MISO Zone 7 is 1% away from not meeting the LCR in 2021/2022.

Line No.

Q. What are the economic and reliability implications of MISO Zone 7 not meeting the LCR?

A. MISO Zone 7 not meeting the LCR will result in the MISO Zone 7 PRA clearing price being set to the Cost of New Entry (CONE, which will be $88,830 / Zone 7 Zonal Resource Credit in the 2019-2020 PRA). For ~140 MWs of Unforced Capacity (the size of a small St Clair unit) that the Company is short to its planning requirement, DTE Electric customers will pay ~$12M in any Planning Year that MISO Zone 7 is even only 1 MW short to the LCR. For ~670 MWs of Unforced Capacity (the size of St Clair units 1, 2, 3, and 6) that the Company is short to its planning requirement, DTE Electric customers will pay ~$60M in any Planning Year that MISO Zone 7 is short to the LCR. Furthermore, the probability of loss of load event (an event in which available capacity is insufficient to serve demand) would exceed the federal reliability standards that govern the resource adequacy planning process.

Q. MISO forecasts future year CIL values in the annual LOLE report. Why not simply use MISO's forecasted CIL?

A. Like most forecasts, MISO's forecasts have error. MISO has publicly recognized that the forecasts of out-year Capacity Import and Export Limits are volatile due to uncertainty and has recommended discontinuing the out-year analysis.[2]

[2]https://cdn.misoenergy.org/20180207%20RASC%20Item%2004b%20Out%20Year%20CIL%20CEL%20Proposal120114.pdf

Q. MISO forecasts future year Per-Unit LRR in the annual LOLE report. Why not simply use MISO's forecasted Per-Unit LRR?

As stated above, MISO's forecasts have errors. Case in point, in MISO's 2017 LOLE Study Report, MISO forecasted the Zone 7 PY 2019/2020 Per-Unit LRR to be 113.2%. However, the actual Zone 7 PY 2019/2020 Per-Unit LRR is 117.2%. This represents a 4% change in two years. Based on a 21,000 MW MISO Zone 7 peak load, the change represents an additional ~840 MW of UCAP required in MISO Zone 7 (a swing in LRR similar in size to over half of all the Company's Tier 2 generating units). Furthermore, assumptions made for the out-year analysis – including load forecasts and portfolio characteristics – create uncertainty in the applicability of the LRR forecast. The following is MISO's LOLE Study Report Per-Unit LRR accuracy for the past four years.

Table 2 – MISO Zone 7 Per-Unit LRR by Planning Year

	Planning Year			
	16-17	**17-18**	**18-19**	**19-20**
Actual	113.2%[1]	114.1%[2]	115.3%[3]	117.2%[4]
Forecast	114.2%[5]	115.1%[5]	113.9%[6]	113.2%[2]
Difference	-1.0%	-1.0%	1.4%	4.0%

Table 2 Sources
1. 2016 LOLE Study Report
2. 2017 LOLE Study Report
3. 2018 LOLE Study Report
4. 2019 LOLE Study Report
5. 2015 LOLE Study Report
6. 2014 LOLE Study Report

As shown in Table 2, it is not uncommon for MISO's Per-Unit LRR projection to be inaccurate by 1% or higher. This change in requirement is at minimum comparable in size to a mid-size Tier 2 unit. Also of note, despite varying forecasted values, the

actual Per-Unit LRR has been increasing substantially over the last several years.

Q. Are the June and September 2018 PACE forecasts referenced on pages 32-34 of MEC Witness Allison's Direct Testimony consistent with the current Planning Year 2019/2020 Per-Unit LRR and CIL?

A. No. MISO posted the 2019/2020 LOLE Study Report in October 2018, after the June and September 2018 PACE forecasts were developed. The MISO Zone 7 shortfalls described on pages 33-34 of MEC Witness Allison's testimony do not include the recent increase in MISO Zone 7 LRR and decrease in MISO Zone 7 CIL.

Q. Does MEC Witness Fagan reference out-year LOLE forecasts?

A. Yes. Witness Fagan repeatedly uses the 2019/2020 and 2024/2025 MISO Zone 7 LRR values from the 2019/2020 LOLE forecast to indicate MISO Zone 7 will have increased headroom and the transmission system will be relatively unconstrained for exchanging capacity (pages 4, 6, 8 of Witness Fagan's Direct Testimony). However, these claims are founded on the assumption that MISO's out-year forecast can be depended on, which recent evidence demonstrates is unwise.

Q. Is MEC Witness Fagan's 2024/25 declining MISO Zone 7 LCR discussion relevant to the Company's St. Clair units forecasted retirements?

A. No. The forecasted period Witness Fagan discusses is beyond the Company's planned retirement dates of St. Clair generation units. Furthermore, MISO has recommended discontinuing out-year forecasts, stating, *"The volatility and changing variables result in the analysis producing limits that should not be used in resource*

planning"[3].

Q. Does Witness Fagan claim active transmission improvements (pp 10-13 of Witness Fagan's Direct Testimony) will lower the MISO Zone 7 Local Clearing Requirement prior to the planned retirement of the Company's St. Clair generation units?

A. No. Witness Fagan's discussion of transmission projects does not indicate the MISO Zone 7 LRR or CIL will change. In other words, MISO Zone 7's local capacity need is not claimed to be changing based on the active transmission projects. The near-term local requirements may continue through the planned retirement of St. Clair.

Q. What are your recommendations?

A. I recommend that the Commission recognizes the capacity-related reliability need and capacity value of the Company's St. Clair 1, 2, 3, and 6 generation units and continues to allow for rate recovery of future capital costs in an effort to support the local capacity needs of the lower peninsula of Michigan.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

[3] https://cdn.misoenergy.org/20180207%20RASC%20Item%2004b%20Out%20Year%20CIL%20CEL%20Proposal120114.pdf

JUDGE WALLACE: And I believe we have cross-examination by MEC NRDC or just MEC?

MR. FISK: MEC, NRDC, and Sierra Club.

JUDGE WALLACE: Right. Thank you, Mr. Fisk.

MR. FISK: Great. Thank you, your Honor.

CROSS-EXAMINATION

BY MR. FISK:

Q Good afternoon, Mr. Arnold.

A Good afternoon.

Q How are you doing today?

A I'm doing well.

Q Good. So you have offered rebuttal testimony in this proceeding that is, is it fair to say, at a high level view of resource adequacy issues?

A In the near term, yes.

Q So near term resource adequacy in MISO Zone 7; is that correct?

A Correct.

Q And on page 3 of your rebuttal testimony starting at line 9 there's a Table 1 there. Do you see that?

A Yes.

Q And in that table you present a capacity demonstration for MISO Zone 7 for planning year 2021-22; is that right?

A That is correct.

Q And planning year 2021-2022 runs from June 1, 2021 through May 31, 2022; is that right?
A Yes.
Q So that capacity demonstration is for a period of after the proposed retirement date for River Rouge Unit 3; is that right?
A That is correct.
Q So that retirement would be reflected in the numbers in this Table 1?
A Assuming that the Company included that in the capacity demonstration in the Staff report, yes.
Q And to your knowledge, they did?
A Yes.
Q And we currently are in MISO planning year 2018-2019; is that right?
A That is correct.
Q And your capacity demonstration is a projection of whether there will be sufficient capacity to meet Zone 7's local clearing requirement in planning year 2021/22; is that right?
A That is correct.
Q And the Local Clearing Requirement is the amount of capacity needed within a MISO zone to meet applicable reliability standards; is that right?
A That's not all standards, but you could say that.

Q O.K. Specifically the standard related to the one, one day loss of load expectation every ten years?
A There's also another standard that needs to be met. That's the planning reserve margin requirement.
Q O.K. Great. And just to make sure I understand the capacity demonstration set forth in Table 1, if you could just briefly walk through the mechanics without worrying about the specific numbers yet? So obviously line 1 is just a forecasted peak demand for Zone 7, right?
A That is correct.
Q And then line 2 shows what is referred to as LRR Unforced Capacity per unit of Peak Demand, right?
A Yes, that is correct.
Q What does that peak represent?
A That's the percentage above the peak load that you need resources for in terms of unforced capacity in order to meet MISO's one day in ten year loss of load expectation.
Q O.K. And so then line 3 of Table 1, the Local Reliability Requirement, that's simply multiplying the peak demand by the LRR Unforced Capacity number; is that right?
A Correct.
Q And the Local Reliability Requirement is the total amount of capacity that is needed to serve the MISO zone in order to ensure the reliability standards are achieved?

A If MISO Zone 7 was all by itself, that's what it represents, yes.
Q So it does -- so it's MISO Zone 7 by itself but it could include imports to meet that, correct?
A No. LRR does not include imports.
Q No imports. O.K. So the imports are shown -- Well, if there's a Capacity Import Limit into Zone 7, correct?
A Correct.
Q That's shown in line 4?
A Yes.
Q And then in line 5 you have a Local Clearing Requirement which represents the local reliability requirement minus the capacity import; is that correct?
A Correct.
Q And line 6 is a level of capacity forecasted to be available in the zone, right?
A Yes.
Q So then in line 7, for the capacity determination you're comparing the total capacity available in the zone of line 6 to the local clearing requirement in line 5; is that right?
A That's correct.
Q The if line 6 is greater than line 5, the zone is projected to have a surplus of capacity; is that right?
A Yes.

Q So in Table 1 you present an update to the Zone 7 capacity demonstration that Staff set forth in Case No. U-18441. Is that right?
A That is correct.
Q And the Staff had forecasted a capacity surplus of 1,220 megawatts in planning year 2021/2122; is that right?
A Could you repeat that?
Q The Staff had forecasted a capacity surplus of 1,220 megawatts in planning year 2021 and '22?
A That is correct.
Q But in your updated capacity demonstration you have identified a surplus of only 1,264 megawatts?
A Yes.
Q And the change in the results between the Staff projection and your capacity demonstration is due to your updating the capacity import limit and the LRR unforced capacity per unit; is that right?
A Yes. I updated them to what's currently in the 2019/2020 planning year LOLE.
Q O.K. And the 2019/2020 LOLE, that's the loss of load expectation requirement?
A Correct.
Q And the Staff report uses the 2018/19 report?
A Yes. Numbers from that report.

Q So for the peak demand, it's line 1 in Table 1, all else being equal a higher peak demand would lead to a less favorable Local Clearing Requirement position; is that correct?
A Assuming it doesn't impact the LRR, then yes.
Q All right.

MR. FISK: May I approach?

JUDGE WALLACE: Yes, you may.

MR. FISK: Mark this as Exhibit MEC-135.

(Document was marked for identification by the Court Reporter as Exhibit MEC-135.)

Q (By Mr. Fisk): So Mr. Arnold, you have been handed an exhibit that's been marked as MEC-135. Is that correct?
A Yes.
Q And that is the 2018/19 LOLE report that we just referenced; is that correct?
A That is correct.
Q Do you have with you the 2019/2020 LOLE report?
A I don't have it right here, no.

MR. FISK: O.K. Can we go off the record for a second?

JUDGE WALLACE: Yes. Off the record.

(Pause.)

JUDGE WALLACE: Back on the record.

Q (By Mr. Fisk): So Mr. Arnold, do you happen to have

Mr. Fagan's testimony, including Exhibit MEC-34 with you?
A Yes.
Q And that's the 2019/2020 Loss of Load Expectation study report; is that correct?
A Correct.
Q And that's the report that you relied on for the updates CIL in per unit LLR?
A Yes.
Q So if you turn to pages 29 of the 2018/19 LOLE report. Are you there?
A Yes.
Q Great. So on this page do you see the planning reserve margin study results for 2018/19 and 2021/22?
A Yes.
Q And under each of those categories there's a line for peak demand. Is that right?
A Yes.
Q And for Zone 7 the 2021/22 number is 21,209 megawatts?
A Yes.
Q And that is the figure that you used in your capacity demonstration, correct?
A Correct. That's consistent with what the Staff reported in their report from earlier this year.
Q So you did not update that peak demand forecast in your capacity demonstration to reflect any changes in peak

demand from the 2019/2020 LOLE report; is that right?
A I'm not aware of an updated forecast for 21/22 for Zone 7.
Q So because the 2019/2020 LOLE report does not specifically have a peak demand forecast for 2021/22, you continued to use the one from the 2018/19 LOLE report; is that right?
A Correct.
Q And if you look at the 2018/19 report, Exhibit 135, the peak demand in 2018/19 planning year is 21,296 megawatts; is that right?
A That's right.
Q And then it goes down a little bit to 21,209 megawatts in 2021/22; is that right?
A Correct.
Q Then flipping over to the next page, that's the results for 2023/24, and the peak demand goes up to 21,384. Is that right?
A That's correct.
Q If you look at the 2019/2020 LOLE report, page 25 provides the 2019/20 and 2022/23 planning reserve margin results; is that right?
A That is correct.
Q And for there, the Zone 7 peak demand for 2019/2020 is 21,208 megawatts?

A Yes.
Q And then it goes down for 2022/23 to 21,038 megawatts. Is that right?
A Correct.
Q Then by 2024/25 it goes down again to 20,982 megawatts?
A That's correct.
Q So the 2019/2020 report shows lower peak demand for Zone 7 than the 2018 report that you continue to rely on for peak demand, correct?
A Incorrect.
Q O.K. How is that incorrect?
A Well, if you look at 23/24 from the -- from the 2018/19 LOLE, you see that the peak load is 21,384.
Q So that's not less than the numbers in the 2019/2020 report?
A I apologize. It is. In 2019/2020 it is lower.
Q And the 2019/2020 LOLE report is lower --
A Is lower, yes.
Q Thank you. And in fact, the load in the 2019/20 LOLE report in all three of the years forecast, the peak demand is lower in that report than the peak demand number you used in Table 1, correct?
A Well, the first year is only one megawatt lower. But yes, all three are lower.
Q And the first year set forth in the 2019/2020 report is

two years earlier than --
A 2019/20.
Q Is two years earlier than the planning year that your Table 1 reflects, right?
A That is correct.
Q O.K. If you could then look at line 2 of your Table 1, this is where you list the LRR Unforced Capacity per unit of Peak Demand. Do you see that?
A Yes.
Q So the higher that number is, the higher the Local Reliability Requirement for the zone would be; is that right?
A Yes.
Q And as a general matter, the higher the forced outage rate for generating units in the zone, the higher the LLR [sic] unforced capacity per unit will be; is that right?
A No. Forced outage rate is not the only variable in the equation. There's also other things like mix of units, unit size, things like that, that change the LRR.
Q O.K. All else being equal, would a higher forced outage rate for generating units in the zone lead to a higher LLR [sic] unforced capacity per unit?
A Well, when you are going year by year, all else isn't equal. But yes, if you are only looking at the same year, you could say higher forced outage rate will lead

to higher LRR.

MR. FISK: Can we go off for one minute?

JUDGE WALLACE: Yes.

(Pause.)

JUDGE WALLACE: Back on the record.

Q (By Mr. Fisk): So the 2019/2020 LOLE report does not actually identify an LRR unforced capacity per unit of peak demand for planning years 2021 and '22, correct?

A That is correct.

Q So you instead just assumed that the number for 2019/20 planning year would apply to 2021/22, correct?

A I do use the 2019/2020 value for 21/22. That doesn't mean that that only applies in 2019/2020, it may also apply in 21/22.

Q And do you have any -- is there any statements by MISO that that, that the 2019/2020 LRR unforced capacity per unit of peak demand applies to 2021/22?

A There is not a statement, but even if there was, MISO's forecast has not been accurate even two years out. As I showed in the direct testimony or rebuttal testimony, even two years ago the forecast for this year coming up was about 4 percent off for LRR.

Q So you used a MISO forecast for a different year to apply to 2021/22, correct?

A It's not a forecast. That's what the actual is for

19/20.
Q And do you know, has MISO forecasted any year beyond 2021/22?
A Yes.
Q And in fact MISO in the 2019/2020 LOLE report forecasts the LLR [sic] unforced capacity declining to 116 percent, correct, in 2022/23?
A In 22/23 it is 116 percent for MISO Zone 7.
Q So rather than using the forecast for the year after the planning year you're looking at, MISO's own forecast, you decided to us the current planning year number?
A Incorrect.
Q O.K. How is that incorrect?
A That's not the current planning year number.
Q I'm sorry. The 2019/20 number?
A Yes. I applied that for the forecast for 21/22.
Q And that 2019/2020 current LLR figure is not for the current year, correct?
A Can you -- I'm not sure what you're saying.
Q So you used a 117.2 percent per unit LRR in your capacity demonstration, correct?
A No. This is not the capacity demonstration.
Q Table 1, line 2?
A O.K. You're referring to this table in this exhibit?
Q Yes. You say 117.2 percent LLR --

A All right. That's the capacity --
Q Per --
COURT REPORTER: Excuse me. There are two people talking.
A Sorry.
Q You're saying Table 1 is not a capacity demonstration?
A Well, the capacity demonstration is an official filing with the State.
Q So Table 1 is your update to the Staff's capacity demonstration, correct?
A It's the Staff's report, yes. It's an update to the Staff report.
Q And on line 6 of page 3 of your rebuttal you refer to that as the capacity demonstration, do you not?
A I do.
Q O.K. So are you saying that your numbers that you added in Table 1 is not a capacity demonstration?
A I just wanted to clarify the question when you asked it because I wasn't sure if you were going somewhere else with it. And so I wanted to clarify that we're talking about this table. So yes, these are both capacity demonstrations.
Q In that capacity demonstration you used a LLR [sic] unforced capacity per unit of peak demand of 117.2 percent?

A It's a LRR, yes.
Q And that 117.2 percent is the value that is included for 2019/20 in MISO's 2019/20 LOLE report; is that correct?
A That's correct. It's the same value.
Q And that is their forecast for 2019/20, correct?
A No, that's the actual for the 2019/2020.
Q It's not the -- so how is that the actual if that's next year?
A That's what will be used. That's what MISO will use in the PRA. It's not a forecast, it's actual.
Q O.K. And then MISO has presented a forecast of the 2022/23 per unit LLR -- LRR, of a 116 percent, correct?
A That is correct.
MR. FISK: May we approach?
JUDGE WALLACE: Yes.
(Document was marked for identification by the Court Reporter as Exhibit MEC-136.)
Q (By Mr. Fisk): Mr. Arnold, you have been handed an exhibit marked MEC-136. Is that correct?
A Correct.
Q This is the Staff report and recommendations from Case No. U-18441. Is that correct?
A That is correct.
Q And is this the same Staff report and recommendations that is referenced on page 3 of your rebuttal testimony

in footnote 4 of Table 1?
A Yes.
MR. FISK: And your Honor, we're going to mark another exhibit, MEC-139, I believe. Going out of order from what I had expected to do but. May I approach?
JUDGE WALLACE: Yes.
(Document was marked for identification by the Court Reporter as Exhibit MEC-139.)
Q (By Mr. Fisk): Mr. Arnold, you have been handed an exhibit marked MEC-139; is that correct?
A That is correct.
Q This exhibit is your revised rebuttal testimony in Case No. U-18403. Is that right?
A That is correct.
Q That's DTE's 2018 PSCR proceeding; is that right?
A That is correct.
Q If you could turn to page 5 of that revised rebuttal testimony. You will recall a few minutes ago we had a discussion about the role of forced outage rates in the LLR -- LRR unforced capacity per unit and peak demand; is that right?
A That is correct.
Q And if you look at, starting at line 14 on page 5 of your rebuttal from U-18403, you have a discussion there about

how per unit LRR is increasing. And you say one of the factors leading to this increase is the rise in the forced outage rate of MISO generating resources. Do you see that?

A Yes.

Q And it was your testimony they're accurate?

A What do you mean by that?

Q Do you believe that one of the factors leading to the increase in per unit LRR has been the rise in the forced outage rate in MISO generating resources?

A Yes.

Q And you go on to discuss that topic through line 4 on page 6 of that rebuttal testimony, correct?

A Correct.

Q O.K. If you could then turn to MEC-136, which is the Staff report from U-18441?

A Which page?

Q If you could turn to page 15?

A O.K.

Q If you look under sub part b, units operating, do you see that?

A Yes.

Q And you see the discussion there in recent years a few Zone 7 generating units have experienced forced outage events. Do you see that?

A Yes.
Q And the Staff then goes on to state, based on the information in U-18441, these units are expected to return to their historical average forced outage rate thereby increasing the amount of ZRCs available to meet Michigan capacity needs in future years?
A One thing to note, when MISO performs a LOLE, they don't use, you don't drop off the year that just happened, they use a span of years. So for the purposes of calculating LRR, it actually uses a five-year average. And so even though maybe they're performing better now, they still have some of that poor performance in their history.
Q So they use a different rolling average than you use in calculating?
A Correct.
Q Five years, the LRR number you are using is, you are projecting it out for three years from now, correct?
A No. When MISO performs the LOLE, it'll be two years from now.
Q I'm saying the number you're using currently, you are using 117.2 percent?
A Yes.
Q For a time period that is three years from now, correct?
A I guess it depends on how you define the years. Because right now they just did the 19/20 report, and I'm

forecasting 21/22. That's only two years apart.
Q O.K. So there would be two additional years factored into --
A Two more years.
Q -- two more years of performance?
A Correct.
Q And the Staff report that we were referring to is from March of 2018. Is that right?
A I believe so.
Q So there would be three years of --
A It's still only two years.
Q Three years from the Staff report. It will be three years of improved forced outage data for the plants that is rolled into the projection LRR for 2021/22?
A I don't believe the Staff claimed that the five-year period was going to improve. Specifically for UCAP ratings, at least what our Company does is, we bake in a forecast for forced outage rates and that will actually already be in the numbers that the Staff has.
Q For three years from now?
A For the four-year demonstration.
Q And that four-year demonstration that you represented would be reflected in the unit UCAP ratings that the Staff is discussing in U-18441?
A It's already reflected in their report.

Q And their report states that the forced outage rate will return to its historical average, thereby increasing the amount of ZRCs available?
A And it's already baked into their forecast, correct.
Q And their forecast used an LRR unforced capacity lower than yours?
A That is correct. They used the forecast at the time.
Q O.K. If you go back to your rebuttal testimony in this proceeding. Page 5, right at the top, you state in line 3 that MISO's forecasts have errors. Do you see that?
A Yes.
Q And by errors, do you mean that at times the actual results end up being different than what MISO forecasted?
A It probably should say error, as in their forecast is different than the actual that happens.
Q So you aren't identifying in your rebuttal testimony actual mistakes that led to MISO forecasts being different than the actual results, correct?
A Not different than their methodology, but their forecast is off from the actual.
Q So when you say error, you're just referring to the fact that the forecast is off from the actual, right?
A Right.
Q You're not saying why it's off?
A Correct.

Q And as you note on page 4, line 18 of your rebuttal, most forecasts have errors, correct?
A That is correct.
Q O.K.
A In this case the error is pretty large, especially given the prompt year for 2019/2020. You could see the error was off by four percent. In terms of UCAP rating, like for the whole zone, that's over 800 megawatts. That's very, very large. Especially when, you know, trying to have some certainty around the forecast.
Q And in previous years they have been off in the other direction, correct?
A They have been high and low. Most recently they have been high. Their forecast has been low.
Q And do you have reason to believe that MISO's forecasts are more likely to be error prone than most forecasts?
A I'm not sure what you mean by that.
Q Well, you refer on page 4, line 18, to most forecasts having errors, correct?
A Correct.
Q Do you have a reason to believe that MISO's forecast is any more prone to having error than most forecasts as you referred to them?
A No. It has error like most forecasts.
Q Including DTE's own forecasts also have error?

A Well, DTE doesn't forecast LRR in terms of using a fundamental method. I do have projections, though.
Q And those could have error?
A They could have error, yes.
Q And on page 6 of your rebuttal testimony, starting at line 15 and going through to line 17, you state that recent evidence demonstrates that it would be "unwise to depend on MISO's out-year forecasts." Is that right?
A Can you state that again?
Q Is it your testimony that recent evidence demonstrates that it would be unwise to depend on MISO's out-year forecasts?
A I think recent evidence does support that. We did lose head room year over year. Our local clearing requirement went up by about a thousand megawatts year over year, and it wasn't expected.
Q And when you refer to out-year, how many years out are you referring?
A I mean beyond the prompt year. The prompt year in this case refers to 2019/2020.
Q So anything beyond 2019/2020 that MISO is forecasting would be unwise to rely on?
A It could be unwise to rely on.
Q And you have never worked for MISO, right?
A I have never worked for MISO, no.

Q You never worked for any other regional transition organization?
A Correct.
Q You never served as an outside expert to MISO; is that right?
A MISO is independent, so they wouldn't hire me as one of the market participants to help them out, I don't think.
Q You never published any technical documents in the area of resource adequacy, right?
A Right.
Q And you never taught any courses in the area of resource adequacy, right?
A Other than internal courses, no.
Q And so is it your position that analysis that incorporates MISO's out-year forecasts is unreliable?
A It's not necessarily unreliable. It's just uncertain.
Q O.K. So on page 6 of your rebuttal testimony, you then reference in line -- starting on line 22 you state that MISO has recommended discontinuing out-year forecasts. Is that right?
A That is correct.

MR. FISK: May we approach, your Honor.

JUDGE WALLACE: You may.

(Document was marked for identification by the Court Reporter as Exhibit MEC-137.)

Q (By Mr. Fisk): Mr. Arnold, you have been handed an exhibit marked MEC-137. Is that right?
A Yes.
Q And this is a MISO document entitled Out-Year CIL and CEL; is that right?
A That is correct.
Q Of February 2018. Is that right?
A Yes.
Q And on page 6 of your rebuttal your reference to MISO discontinuing out-year forecasts is with regards to MEC Witness Fagan referencing MISO Zone 7's -- MISO's forecasts of declining LCR for Zone 7. Is that right?
A That is correct.
Q And the language that you quote starting on line 23 on page 6 and going over to line 1 on page 7 of your rebuttal, that language is found in this document that I marked as MEC-137?
A That is correct.
Q O.K. And this document, MEC-137, nowhere discusses discontinuing out-year forecasts of LCR, correct?
A Well, the CIL is part of the LCR, so I guess it depends on how you -- how you interpret that.
Q Well, MISO is not -- can you point me to any page in MEC-137 where MISO recommended discontinuing out-year forecasts of LCR?

A There -- in this document they're recommending stopping the forecast part of calculation of LCR.
Q So there's nowhere in this document that they recommend no longer forecasting out-year LCR itself, correct?
A Only part of it, correct.
Q And in fact, the 2019/2020 LOLE report continues to forecast in the out-years, correct?
A Forecast what?
Q Forecast LRR, correct?
A Correct, but they don't forecast CIL, and therefore you cannot calculate LCR.
Q And Witness Fagan's testimony, as you note on lines 12 to 13 of your rebuttal, page 6, uses MISO Zone 7's LRR forecast, correct?
A That is correct.
Q And those are out-year MISO forecasts, correct?
A That is correct.
Q And MISO has not discontinued doing those, correct?
A What do you mean by "those"?
Q Those LRR forecasts.
A Correct. MISO is still performing those.
Q If you could go back to the Staff report from 18441, Exhibit MEC-136. Do you also have Exhibit MEC-39 to Mr. Fagan's testimony?
A Yes.

Q And Exhibit MEC-39 to Mr. Fagan's testimony is the MISO 2018/2019 Planning Resource Auction Results; is that right?
A That is correct.
Q And if you turn to page 10 of those planning resource auction results, there is a chart there that provides various results by MISO zone; is that right?
A That is correct.
Q Then if you also take the Staff report, Exhibit MEC-136, and turn to page 12 of that document?
A I'm there.
Q And if you look on, in the Staff report on page 12, if you look at line 2 in Table 1, the Staff for 2018/19 planning year has a Local Clearing Requirement for Zone 7 of 20,769. Is that right?
A For planning year 18/19?
Q Yes.
A Yes.
Q And the MISO Planning Resource Auction Results that are in Exhibit MEC-39, the LCR for Zone 7 was 20,628 megawatts. Is that right?
A Which page are you on?
Q Page 10 of exhibit MEC-39.
A On this page I only see exports and imports limits.
Q Page -- you're in the April 13, 2018, Planning Resource

Auction Results document?
A I'm sorry. I'm there now.
Q O.K. Great. So page 10 of that document. And a Local Clearing Requirement for MISO Zone 7 of 20,628 for the 2018/19?
A That is correct.
Q So the actual LCR was around 140 megawatts lower than the Staff projection in Table 1 of Exhibit MEC-136. Is that right?
A That is correct. Things vary from the LOLE study to the PRA.
Q And looking at the Planning Resource Auction Results, on page 10 it identifies for Zone 7 a Total Offer Submitted of 22,036 megawatts. Is that right?
A Yes.
Q O.K. And that amount is approximately 1400 megawatts higher than the Local Clearing Result. Is that right?
A Yes.
Q So that means that in 2018/19 offers exceeded the Zone 7 Local Clearing Requirement by approximately 14 million megawatts for the 2018/19 planning year?
A Correct. And this was before the recent changes that increased our LCR by about a thousand.
Q And the total capacity committed according to the Planning Resource Auction Results on page 10 was 21,801

megawatts; is that right?
A That's right.
Q And subject to check, that's a difference of about 1173 megawatts from the Zone 7 Local Clearing Requirement?
A I'll take your word for it.
Q And looking at the Staff report, page 12 of MEC-136, their forecasted anticipated LCR position for planning year 2018/19 was 782 megawatts; is that right?
A That is correct.
Q So the actual capacity committed in the auction was almost 400 megawatts more than the surplus that the Staff had forecasted, correct?
A That is correct.
Q If you go back to Table 1 on your rebuttal testimony page 3, at line 6 you use the same amount of capacity, available capacity, 21,910 megawatts that the Staff did, correct?
A Correct. These are the resources that were committed four years out in the report.
Q So you did not update the amount of capacity available in -- in Zone 7 for your capacity demonstration set forth in Table 1 of your rebuttal testimony, correct?
A Correct. I wouldn't know whether or not those resources would be around in four years or not.

Q So of the factors in Table 1, you updated the two factors that made the anticipated LCR position less favorable, but you did not update the peak demand or the amount of capacity available in Zone 7. Correct?
A I'm not aware of other sources of data that would give me that.
Q And in rebuttal page 3 of the Table 1, line 4, that's your forecasted Capacity Import Limit; is that right?
A That's correct.
Q And Capacity Import Limit is impacted by, among other things, voltage constraints; is that right?
A That is correct.
Q In fact, the capacity import limit for MISO Zone 7 is primarily limited due to a voltage constraint on the Pioneer 120 kV bus line; is that right?
A Which report are you referring to?
Q I'm referring to MISO's analysis of the --
A Is that a certain LOLE study?
Q It's the 2019/20 CIL CEL studies and time line. Do you know how MISO determined the CIL for Zone 7?
A Yes. They described it in their LOLE study.
Q And do you know if MISO identified a voltage constraint as the limiting element for the CIL in MISO Zone 7?
A I really have to see that document.
Q So you don't know off --

A Off the top of my head, based on my knowledge, I believe it is that. But I'd want to verify it.
Q Do you know, are voltage constraints something that can be addressed through transmission projects?
A There can be transmission solutions, yes.
Q So transmission projects or solutions can impact the capacity imports for a zone; is that right?
A It can -- transmission projects can impact the CIL, yes.
Q And the CIL value that you used is MISO's projection for 2019/2020, correct?
A I would say I just kept it, I kept it flat from that value, yes.
Q So MISO projected it for planning year 2019/20?
A I kept my value at their same level, yes.
Q O.K. You did not carry out any modeling to determine that the CIL in planning year 21/22 would be the same, correct?
A Correct.
Q O.K. If you turn to rebuttal page 7, lines 3 to 6, you reference there MEC Witness Fagan's claim that active transmission improvements would lower the MISO Zone 7 Local Clearing Requirement. Do you see that reference?
A That is correct.
Q You have not evaluated how such transmission improvement may impact the CIL for MISO Zone 7, correct?

A Correct. Based on the information from MISO, and based on our internal company information, and even ITC, I don't know of any projects that would impact CIL, where someone has quantified what that would be.
Q But you have not evaluated that question?
A Correct.
Q And you have not that evaluated how such transmission improvements may impact a local clearing requirement for MISO Zone 7, correct?
A Can you state that again?
MR. FISK: Can you read that back?
(The record was read aloud by the court reporter as follows: "Q And you have not that evaluated how such transmission improvements may impact a local clearing requirement for MISO Zone 7, correct?")
A The Company did not perform any modeling.
MR. FISK: If we could go off for one second.
JUDGE WALLACE: Off the record.
(Pause.)
MR. FISK: May we approach?
JUDGE WALLACE: Yes.
(Document was marked for identification by the Court Reporter as Exhibit MEC-138 Confidential._
JUDGE WALLACE: Back on the record.

Q (By Mr. Fisk): Mr. Arnold, you have been handed an exhibit that has been marked 138-C; is that correct?
A That is correct.
Q And this exhibit contains confidential information, so please don't disclose anything on the substance of this exhibit. But I just wanted to confirm that this is -- you were one of the respondents on this response and the attachments; is that right?
A That is correct.

MR. FISK: Your Honor, I'd like to move Exhibit 138-C into the record.

JUDGE WALLACE: All right. Is there any objection to the admission of MEC Exhibit 138-C?

MR. CHRISTINIDIS: Your Honor, no objection from the Company to the extent it's protected consistent with the protective order.

JUDGE WALLACE: All right. Hearing nothing else, the exhibit is admitted.

MR. FISK: Thank you, your Honor. Then I'd also like to move Exhibits MEC-135, -136, -137, and -139.

JUDGE WALLACE: O.K. So that's 135, 136, 137, and 139.

MR. FISK: Yes.

JUDGE WALLACE: Is there any objection to

the admission of MEC Exhibits 135, 136, 137, and 139?

MR. CHRISTINIDIS: May we have a moment, your Honor?

(Pause.)

MR. CHRISTINIDIS: No objection, your Honor.

JUDGE WALLACE: Hearing no objection, Exhibits MEC-135, -136, -137, and -139 are admitted.

MR. FISK: Thank you, your Honor. And if we could have two minutes, I think I'm done. But I just want to check with my co-counsel.

JUDGE WALLACE: Off the record for a few minutes.

(Brief in-place recess.)

MR. FISK: Thank you.

JUDGE WALLACE: Back on the record.

MR. FISK: I have no further questions.

JUDGE WALLACE: O.K. Does anyone else have anything for Mr. Arnold? All right. Let's go off the record.

(Discussion was held off the record.)

JUDGE WALLACE: We're back on the record in Case No. 20162. Mr. Christinidis, do you have any redirect for Mr. Arnold?

MR. CHRISTINIDIS: No redirect, your

Honor. Thank you.

JUDGE WALLACE: Thank you very much, Mr. Arnold. You are excused.

(The witness was excused.)

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JUDGE WALLACE: Next is Ms. Dimitry.

(Document marked for identification by the Court Reporter as Exhibit No. A-12.)

\- - -

I R E N E M. D I M I T R Y

was called as a witness on behalf of DTE Electric Company and, having been duly sworn to testify the truth, was examined and testified as follows:

JUDGE WALLACE: All right. Mr. Christinidis.

DIRECT EXAMINATION

BY MR. CHRISTINIDIS:

Q Can you please state your name and business address for the record?

A Irene Dimitry, One Energy Plaza, Detroit, Michigan 48226.

Q And did you cause to be filed with the Commission a document entitled Qualifications and Direct Testimony of Irene M. Dimitry, consisting of a cover sheet and 31 pages of questions and answers?

A Yes.

Q And did you also cause to be filed with the Commission a document entitled Rebuttal Testimony of Irene M. Dimitry, that consists of a cover sheet and 18 pages of questions and answers?
A Yes.
Q And any changes to make to either your direct or rebuttal testimony?
A No.
Q Is that, then, the direct and rebuttal testimony you're adopting today?
A Yes.
Q And you're also sponsoring several exhibits and schedules associated with your direct testimony in this case, correct?
A Yes.
Q Those direct exhibits are designated as Exhibit A-12 Schedule B5.6, consisting of two pages, and Exhibit A-12 Schedule B6, consisting of five pages, correct?
A Yes.
Q Any changes to those direct exhibits and schedules?
A No.
Q Are those, then, the exhibit and schedules you're adopting today on the stand?
A Yes.
Q And it's correct you're not sponsoring any rebuttal

exhibits?

A Correct.

MR. CHRISTINIDIS: With that, your Honor, the Company would move to bind into the record the qualifications, direct testimony, and rebuttal testimony of Irene M. Dimitry, and move the admission of Exhibit A-12 Schedules B5.6 and B6 at an appropriate time, and tender Ms. Dimitry for cross-examination.

While I'm thinking about it, have we admitted the exhibits associated with Mr. Arnold, your Honor?

JUDGE WALLACE: Mr. Arnold had one Company exhibit, just one, and it was three schedules, and they were all in one, and then we did admit MEC's exhibits as well.

MR. CHRISTINIDIS: O.K. Thank you, your Honor.

JUDGE WALLACE: Yes, those were all admitted.

So is there any objection to binding in the testimony, direct and rebuttal testimony of Ms. Dimitry, as well as Exhibit A-12 Schedule B6 and A-12 Schedule B5.6 at the appropriate time? (No response.)

Hearing no objections, Ms. Dimitry's testimony and rebuttal testimony are bound into the

record, and we will admit Exhibit A-12 once all the pieces of A-12 have been sponsored.

(Testimony bound in.)

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

IRENE M. DIMITRY

DTE ELECTRIC COMPANY
QUALIFICATIONS OF IRENE M. DIMITRY

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Q. Please state your full name, title, business address and by whom you are employed?

A. Irene M. Dimitry, Vice President of Business Planning & Development, One Energy Plaza, Detroit, Michigan, 48226. I am employed by DTE Energy Corporate Services, LLC, a subsidiary of DTE Energy.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q. What is your educational background?

A. I graduated from Wayne State University in 1989 with a Bachelor of Arts Degree in Business Administration. In 1994, I received a Masters Degree in Business Administration from the University of Michigan.

Q. Please describe your work experience?

A. I began my career with GM in the GMC Truck Division and worked there from 1989-1992. I served in several roles within the division's Marketing organization. My employment with DTE Electric began in 1994 as part of the Company's Professional Opportunity Program. Over the years, I held a number of positions with increasing leadership responsibilities in areas that include: Business Planning, DTE Electric's Ann Arbor Service Center, the President's Staff organization, Customer Marketing, Customer Billing, and Enterprise Performance Management.

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I also served as the Director of Strategy and Planning for DTE Electric. In this role, I was responsible for Integrated Resource Planning, Customer Research, general rate case support and strategic initiatives related to the Company's business plans.

Prior to my current position, I was the Vice President of Marketing and Renewables. In this role, I was responsible for planning and executing energy efficiency and renewable energy activities for DTE Electric and DTE Gas consistent with 2008 Public Act 295 (2008 PA 295 or PA 295). I have been responsible for planning and executing DTE Electric's renewable energy activities since the enactment of 2008 PA 295, and for planning and executing DTE Energy's energy efficiency / energy waste reduction activities since 2010.

Q. What is your current position and what are your current responsibilities?

A. Currently, I am the Vice President of Business Planning and Development. In this role, I am responsible for Renewable Energy, Energy Waste Reduction, Corporate Energy Forecasting, Business Planning, Integrated Resource Planning, and Customer Choice functions.

Q. Have you previously sponsored testimony before the Michigan Public Service Commission?

A. Yes. I sponsored testimony in the following cases:

U-15806-RPS	DTE Electric's 2009 Renewable Energy Plan case
U-16356	DTE Electric's 2009 Renewable Cost Reconciliation case
U-16582	DTE Electric's 2011 Renewable Energy Plan
U-17767	DTE Electric's 2014 Rate Case

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1	U-18014	DTE Electric's 2016 Rate Case
2	U-18255	DTE Electric's 2017 Rate Case
3	U-18419	DTE Electric Certificate of Necessity
4	U-18441	Capacity Demonstration
5	U-18444	Process for Forward Locational Requirement

DTE ELECTRIC COMPANY
DIRECT TESTIMONY OF IRENE M. DIMITRY

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Q. What is the purpose of your testimony?

A. The purpose of my direct testimony is to:

1) Discuss the development of the demand side management (DSM) efforts that DTE Electric is conducting and provide support for the expenditures and activities associated with the continuation of existing DSM programs and the start of future DSM programs; and

2) Discuss the economic analysis completed by the Company regarding the continued operations of River Rouge Unit 3 until its planned retirement in 2020

Q. Are you sponsoring any exhibits in the proceeding?

A. Yes, I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-12	B5.6	Demand Side Management Capital Expenditure
A-12	B6	River Rouge Unit 3 NPVRR Analysis

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. How is your testimony organized?

A. My testimony consists of the following two parts:

Part I Demand Side Management Programs

Part II River Rouge Unit 3 Evaluation

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Part I: Demand Side Management Programs

Q. How much has the Company invested in Demand Side Management (DSM) programs?

A. The Company has spent $25.4 million in capital expenditures associated with DSM programs from 2016 through December 31, 2017. DTE Electric's existing programs during that time include:

- Interruptible Air Conditioning (IAC)
- Programmable Controllable Thermostat (PCT)
- DTE Energy Insight

Shown below in Figure 1 is the Company's historical capital expenditures since 2016.

Figure 1: Historical DSM spend from 2016

$ Thousand	**Historical 12 Mo. Ended 12/31/2016**	**Historical 12 Mo. Ended 12/31/2017**	**Historical 2016-2017 Total**
Interruptible Air Conditioning	$7,353	$4,304	$11,657
Programmable Controllable Thermostat	$0	$2,074	$2,074
DTE Energy Insight	$5,349	$6,295	$11,644
Total	$12,702	$12,673	$25,375

Q. How much is the Company forecasting to spend on DSM programs during 2018, 2019, and through the end of the projected test year April 30, 2020?

A. The Company is forecasting to invest $15.5 million through the bridge period of January 2018 through the month ending April 2019 and $15.0 million in the projected test year ending April 2020 on DSM programs. A detailed breakdown of these capital expenditures by program is shown in Exhibit A-12, Schedule B-5.6, page 1 of 2, column (e) and (f). The Company is planning to continue investing in IAC, PCT and DTE

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Energy Insight programs. In 2018, DTE Electric began deployment of the Bring Your Own Device (BYOD) program and will continue developing additional DSM pilots. In addition, the Company is forecasting to spend $0.4 million in operation and maintenance (O&M) expenses in support of DSM programs. Associated O&M expenses are shown on CompanyWitness Mr.Clinton's Exhibit A-13, Schedule C-5.8, page 1 of 1, line 9, column (k).

Q. How do the O&M expenses support DSM programs?

A. The expense reflects the funding needed to support the marketing and development of the DSM portfolio of programs, including staffing requirements of the exisitng programs.

Q. Why has the Company been investing in DSM programs?

A. Planned or unplanned power plant retirements, new energy legislation, regulatory requirements, and changing environmental regulations have been driving change to the energy landscape in the State of Michigan. As coal plants retire and new resources must be built, developed, or acquired to ensure resource adequacy, DSM will be an important part of DTE Electric's resource portfolio. These DSM programs are designed to help reduce enrolled customers' energy use during peak hours, providing value to both the utility and the customer through lower capacity costs.

The Company believes that DSM programs belong in a utility system framework and within the comprehensive context of an integrated resource planning process. The DSM Organization within DTE Electric develops, validates, and manages these technologies and programs. The DSM Organization works with the Company's generation strategy

and integrated resource planning teams to determine the timing and the amounts of new or additional DSM programs that are viable alternatives within the Company's integrated resource plan, and with the Company's generation optimization team to operate the DSM programs.

Each DSM program outlined below offers customers a range of options consisting of products, customer incentives, tariff structures, and education based on their risk profiles and willingness to curtail energy usage during peak hours. As part of the development of the DSM programs in integrated resource planning, DTE Electric evaluates new programs, customer effectiveness, program acceptance and validates technologies that deliver benefits to utility customers. By developing a portfolio of functioning DSM programs, the Company expects to continue providing secure, reliable, and sustainable energy supply to its customers under a changing generation capacity and energy landscape in the coming years.

<u>Interruptible Air Conditioning (IAC)</u>

Q. What is the status of the Company's IAC program?

A. Beginning with approval requested in the December 2014 general rate case, Case U-17767, the Company embarked on a long-term plan to improve programs and repair existing IAC equipment. The goal of this plan was to extend the equipment life and increase available Midcontinent Independent System Operator (MISO) acknowledged capacity. This program upgrades the existing IAC infrastructure from an antiquated one-way radio system to a two-way communication protocol enabled Load Control Device (LCD) that utilizes the existing advanced metering infrastructure (AMI) technology. The new two-way communication infrastructure provides significant

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advantages over the one-way radio system that has been in the field since the 1970s, and is prone to malfunctioning, difficult to service, and in need of repair. The new LCDs reside within and utilize the existing AMI device, provide a two-way communication tool, deliver improved diagnostic capabilities, as well as provide more effective remote equipment control. The Company intends to replace all the old IAC switches with new LCDs, adding up to 278,000 replaced units by 2026 and translating into a total of 221 MW of MISO acknowledged nameplate capacity for DTE Electric.

Q. Why is the Company making these improvements?

A The Company is making these improvements for several reasons. The existing one-way radio paging infrastructure is quickly becoming obsolete. The equipment currently in use by the Company is no longer being manufactured and replacement parts are very difficult to find for the outdated 56K modem technology. Additionally, by utilizing a two-way communication infrastructure, the Company has the ability to validate the status of each LCD remotely. This functionality allows for the Company to identify and diagnose non-operational LCD units through the AMI network without having to physically visit the customer location. The limitations of the antiquated one-way infrastructure interfere with the ability to receive full capacity credit for the program in MISO. The Company has increased the MISO acknowledged capacity on the IAC program as the replacement of the old technology is occurring. The Company is currently claiming 135 MW of available capacity for the program in 2018.

Q. What are the Company's planned efforts in managing the IAC program going forward?

A. Under its long-term IAC capital improvement plan, DTE Electric installed new devices and is currently planning to purchase and install additional devices. Figure 2 below details historical and projected installations.

Figure 2: Historical and Projected LCD Installations

	Historical 12 Mo. Ended 12/31/2017	Projected 12 Mo. Ending 12/31/2018	Projected 4 Mo. Ending 04/30/2019	Projected 16 Mo. Ending 4/30/2019	Projected 12 Mo. Ending 4/30/2020
New or Planned LCDs Installed	28,190	29,000	8,000	37,000	30,000
Cumulative Total Installed	60,190	89,190	97,190	97,190	127,190

The Company continues to use Continuous Improvement opportunities to drive program cost efficiencies. One recent example was a process change to implement a route optimization process. This approach decreases drive time, maximizes installations and saves money.

The forecasted expenditures in Exhibit A-12, Schedule B-5.6, page 1 of 2, line 1, column (e) and (f) for the projected bridge period January 2018 through April 2019 ($5.9M), and the projected test year period through April 30, 2020 ($4.9M) reflect the continuation of the existing IAC replacement as approved by the Commission in its Orders dated December 11, 2015 for Case No. U-17767, January 31, 2017 for Case No. U-18014, and April 18, 2018 for Case No. U-18255. The Company plans to continue increasing the capacity of the program, and thus accelerating the replacement of the obsolete technology (one-way radio system) to meet its targeted completion in 2026.

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Programmable Controllable Thermostat (PCT)

Q. What is the PCT Program in which DTE Electric is investing?

A. The Programmable Controllable Thermostat (PCT) pilot program is available to residential customers and requires customers to enroll in the Dynamic Peak Pricing (DPP) tariff. The customer's enrollment allows the Company to send a pricing signal to a PCT installed in the customer's home during a DPP event. Per the D1.8 tariff, customers are notified by 6 PM the day prior to the initiation of a DPP event. During a DPP event, the PCT is sent a pricing signal and raises the thermostat by 4 degrees. The PCT uses Wi-Fi to receive the signal from the utility during an event. The customer can override this action by adjusting their thermostat settings during DPP events. However, as part of participating on the DPP tariff, such manual over-rides of the utility PCT signals will drive a customer's bill to be notably higher.

The Company does not shut off the Heating Ventilation and A/C system or any other appliance in the home as part of the PCT program. The thermostat control only occurs between 3 PM and 7 PM Monday through Friday (excluding holidays) and is limited to 20 events per year.

Q. Why has the Company been investing in the PCT Program?

A. The purpose of the program is to lower peak-hour electric consumption by residential customers. DTE Electric continues to implement the PCT program to leverage the results and valuable customer behavioral information gained from the SmartCurrents pilot study conducted during 2010-2013, which was funded by an American Reinvestment and Recovery Act Smart Grid Investment Grant (SGIG). The results of the pilot suggested that customers can reduce their electricity usage by up to 40% during

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on-peak hours and save up to 15% on their electric bills by making small changes in their behavior while participating in a dynamic peak pricing program in conjunction with a PCT.

Q. How did the Company pursue implementation of the PCT program it set forth in Case No. U-18014?

A. After the MPSC order in Case No. U-18014 was issued in January 2017, the Company issued a Request for Proposal (RFP) to third Party Implementation Contractors. Evaluations of the RFP responses were conducted during the second quarter, and contract negotiations began in the third quarter of 2017. Additionally, the Company implemented a 50-unit technology test in the third quarter of 2017 to gauge customer interest and the ability to deliver signals to devices in the field. The initial large-scale purchase of the thermostats occurred in late fourth quarter 2017 and DTE Electric began marketing the program to recruit and enroll customers in the first quarter of 2018.

Q. What was the Commission's ruling in Case No. U-18255 for the PCT Program?

A. In its April 18, 2018 Order Case No. U-18255 the Commission observed, "Staff contends that the installation of 50 PCTs does not demonstrate success or justify the need for 25,000 more, noting that the utility still has another 9,950 to install from the last rate case". The Commission then adopted the recommendation of the ALJ, which denied the $6.133 million requested to expand the PCT program beyond the expenditures approved in Case No. U-18014 rates to support the installation of 10,000 units. The Commission agreed that complete installation was not necessary to support increased funding, but a showing of initial success is required.

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Q. What is the actual and forecasted progress in enrolling customers in the PCT program?

A. The Company has enrolled 2,000 customers on PCTs since the launch of the program in 2018 and is forecasting to enroll 7,000 customers by the end of 2018 as well as complete the enrollment of 10,000 units by the summer of 2019. The Company is proposing an additional investment in the PCT program as shown by the forecasted expenditures in Exhibit A-12, Schedule B-5.6, page 1 of 2, line 2, column (e) and (f) for the bridge period January 2018 through April 2019 ($6.2M), and the projected test year period through April 30, 2020 ($3.4M) given the enrollment success of the program since inception and the performance of the 2017 PCT pilot, as described in more detail below. These additional investments would enable enrollment of a total of 17,000 customers in the PCT program, up from the 10,000 customer level supported by the funding approved in Case No. U-18014 and reaffirmed in Case No, U-18255, as shown in Figure 3 below.

Figure 3: Historical and Projected PCT Enrollments and Capital Spend

	12 Months Ending 12/31/2018	**4 Months Ending 4/30/2019**	**16 Months Ending 4/30/2019**	**12 Months Ending 4/30/2020**
Phase 1 Units	7,000	3,000	10,000	
Phase 1 Capital	$4.6M	$1.6M	$6.2M	
Phase 2 Units				7,000
Phase 2 Capital				$3.4M

Line No.

Q. What information is the Company relying on to support its current rate request for the PCT program?

A. The Company ran a 50-customer technology-test pilot program in the fall of 2017 and the results of the pilot are similar to the 2013 SmartCurrents pilot. For the fall 2017 pilot, the Company collected data for 3 DPP events in September during which the average peak temperature reached 89 degrees. The Company saw an average reduction of 1.0 kW per participating customer over the course of the 3 DPP events called in 2017. This value is higher than the Company's results in the 2012 Smart Grid Investment Grant program of 0.75 kW per customer and higher than the impacts projected in Case Nos. U-18255 and U-18419. The Company sees the increased reduction as a positive performance indicator and believes it is supportive of additional investment in the program. Figure 4 below showcases the data collected for one of those 3 DPP events. The representative data below shows that in a DPP event where the PCT program is called upon by the Company, the PCT customers show a steep decline in usage during the critical hours of the event when compared to DPP-only customers. During the September 26, 2017 DPP event, the average PCT customer reduced their consumption by 1.05 kW.

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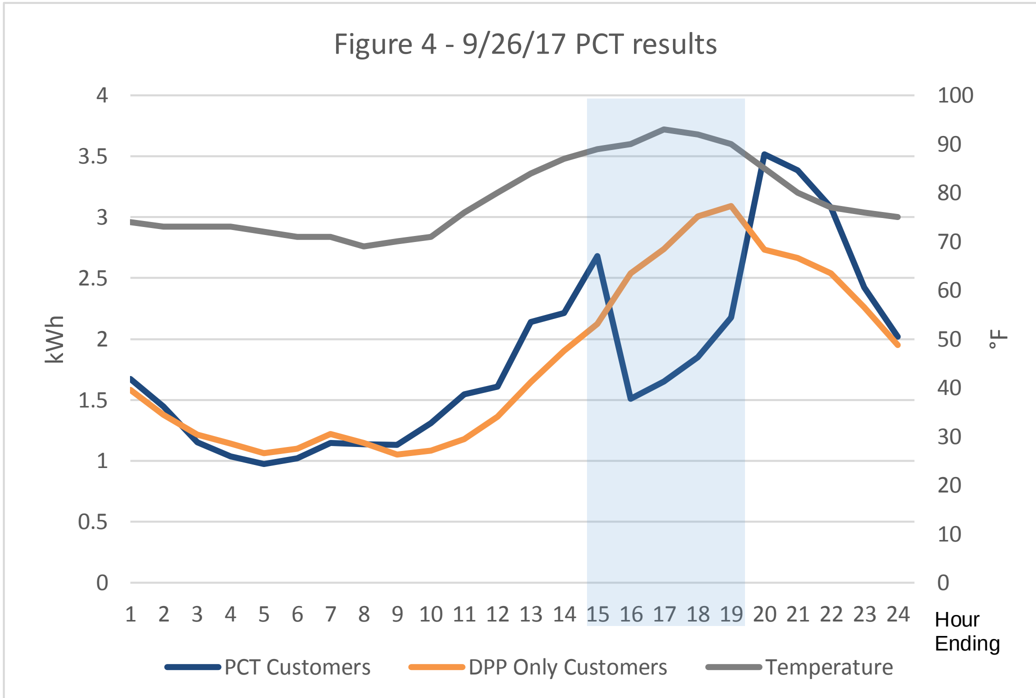

Figure 4 - 9/26/17 PCT results

Q. How is the Company proposing to measure the performance of the PCT program?

A. The Company is following existing measurement and verification processes to establish the peak demand reduction of those customers enrolled in the PCT program. The Company separates those customers with PCT technology from those without PCTs on the existing DPP rate and measures the relative load reductions at the meter for the peak events. The Company verifies and analyzes a customer's actual load profile before, during, and after an event with hourly data to determine reductions. Per the Commission reporting requirements in Case No. U-18441, this information will be included as Internal Demand Response Programs that are applied as an adjustment to the Peak forecast in the annual reporting template for Capacity Demonstration filings.

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Q. As part of the PCT program development, is the Company evaluating the possibility of requiring customers to pay some amount for the thermostat devices?

A. Yes. Under the current PCT program, the Company purchases the thermostats for installation in the customer's home. The thermostats are currently provided to the customer free of charge and the customer self-installs the unit or can request installation assistance from the Company. The Company will continue to monitor and evaluate all options for customer participation, including having customers pay for a portion of the hardware or device in order to have enrolled customers more invested in the program. During the small-scale pilot in 2017, all customers enrolled in the program installed and connected their device. Of those customers, 74% participated in the 3 DPP events called last fall by not overriding the signal to the thermostat. In 2018, as a consequence of the program set forth in U-18014 and the associated rate approvals, the Company has enrolled 2,000 customers and 65% of those PCTs distributed were installed and connected by customers through May 25, 2018. The Company is currently following up with the remaining customers who have enrolled in the program but not yet installed the PCTs to encourage installation or provide assistance with the installation of the PCT on an as needed basis.

The Company will continue to monitor customer engagement and installation of the program's PCTs and reserves the option to begin charging customers for the hardware in the future, if needed, to increase customer engagement and result in better participation during DPP events (e.g., create more "skin in the game" for customers). If customer charges are implemented, the Company would use the funds collected from customers to reinvest in the program, by acquiring hardware or increasing marketing efforts.

Q. What are the Company's planned efforts to manage the PCT Program going forward?

A. As of May 31, 2018, the Company has enrolled 2,000 customers in the PCT program. The Company is forecasting to have 7,000 customers enrolled by year end 2018 as well as 10,000 customers enrolled by the summer of 2019. The Company is requesting funding in rates to enable enrollment of an additional 7,000 customers in the PCT program by the end of the test year in April 2020. Continued investment in this program will reduce the impact of residential load on peak demand, lowering the Company's need to secure additional generation capacity, and improving customer affordability. The PCT program further leverages the Company's involvement in new technology, including the existing AMI infrastructure, which provides the interval data needed for billing and hourly pricing under the PCT program. It also positions DTE as an industry leader in DSM and provides another program in a portfolio of options for customers to manage their electricity usage and bill.

Given the results of the 2017 pilot program and the 2,000 units enrolled at the time of this filing, DTE Electric is requesting $6.2 million in capital expenditures during the bridge period January 2018 through April 2019 and $3.4 million through the projected test period ending on April 30, 2020, to purchase approximately 7,000 additional PCTs. Based on the filing of this request and the timing of the expected approval in the resulting final Order, the Company would install an additional 7,000 units by the summer of 2020 with the capacity being available by the summer of 2020 for planning purposes. This quantity reflects a reasonable estimate as a continuation of the program. Please, refer to the Exhibit A-12, Schedule B5.6, page 1 of 2, line 2, column (e) and (f), for the total capital expenditure request.

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DTE Insight

Q. What is the DTE Insight Program?

A. The DTE Insight program centers on a mobile application that is integrated with AMI and helps residential customers monitor and manage their energy use. Users of the DTE Insight mobile application can view their prior day's energy usage on an hour-by-hour basis, which helps customers better understand how recent weather and behaviors can impact energy usage and savings. When paired with an Energy Bridge (EB) device, the DTE Insight program participants can obtain real-time energy information. EB devices collect energy consumption data by connecting wirelessly to the automated meter and storing highly granular interval data in the EB at the customers' home, allowing customers to gain access to this data through their smart phone or other device. As part of integrated resource planning, broad deployment and usage of the DTE Insight app and EB devices can reduce peak demand and potentially mitigate or defer the need for future supply side resources. The DTE Insight program generated 1,818 kW of coincident peak savings in 2017 as stated in Exhibit A-14, column (j), row 12 in the Energy Waste Reduction (EWR) reconciliation for program year 2017 Case No. U-20029 included with Company Witness Brannan testimony.

Q. What did the Commission approve in Case No. U-18255 for the DTE Energy Insight Program?

A. The MPSC approved $9.9 million in capital in rates over the 22-month period ending October 31, 2018 to continue to invest in the DTE Insight program to enhance successful demand side management options. From January 2017 through October of 2018, the Company is forecasted to spend $6.9 million in capital for the DTE Insight program. The lower than planned spend is driven primarily by a new vendor contract for field

support expenses. As these lower field support expenses are reflected in our request for capital expenditures included in this case, the Company does not expect to underspend again on the DTE Insight program.

Q. What are the most updated metrics regarding the development and implementation of the DTE Insight program?

A. The Company continues the development and implementation of the DTE Insight program throughout 2018. As shown in Figure 5, the following metrics reflect the continuous and increasing customer engagement and participation in the program:

Figure 5 DTE Insight Metrics

	Cumulative Data as of Dec 31, 2015 (a)	**Cumulative Data as of Dec 31, 2016 (b)**	**Cumulative Data as of Dec 31, 2017 (c)**	**Cumulative Data as of Apr 30, 2018 (d)**	**Increase in Year 2017 (c) – (b)**
Unique Household Downloads	59,080	115,741	157,372	165,634	41,631
Total Customer Downloads	119,607	245,533	365,687	393,149	120,154
EBs Purchased	35,000	65,000	106,000	106,000	41,000
EBs Requested	25,261	51,833	68,569	70,054	16,736
EBs Shipped	16,377	36,815	58,999	59,795	22,184
EBs Returned	0	853	5,619	6,243	4,766

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Q. Has the Company made any improvements in calendar year 2017 for the DTE Insight program?

A. During 2017, the Company improved the success rate of customers that connected their energy bridge device to the AMI without assistance from 82% to 93%. The primary driver was a new generation of energy bridges with much more sophisticated software/hardware that simplifies the process of wirelessly connecting the energy bridge to the customers' AMI meter (i.e., the binding process). In addition, a customer engagement campaign began in February 2017 and ran through December 2017. As described in Case U-18255, EB devices shipped to customers that were not installed amounted to 12,731 as of December 31, 2016. At the end of this customer engagement campaign, the Company saw approximately 1,800 targeted customers connect their devices and almost 4,800 targeted customers return their devices, thereby minimizing waste and ensuring more actual program benefits.

Q. What progress has the Company made with analyzing charging customers for the energy bridge devices?

A. The Company has completed its research and design work on instituting a new customer charge for the energy bridge device. In 2018, the Company plans to test a charge approach that offers a six-month free trial period and then charges $0.99 per month in perpetuity. There will also be a $25 one-time charge placed on the bill when customers move or contact the Company to report the device lost or damaged. In the case of move-outs, this one-time fee will be waived when the energy bridge device is returned to the Company. The intent of this design is to improve customers' engagement with the program without making it too complicated or prohibitively expensive. It is not the Company's intent to charge each participant the full cost of the energy bridge. Money

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collected through this charge will be used to offset program expenses and DTE Electric's overall revenue requirement. The timing for implementing this charge is aligned with the release of the new vendor platform for the DTE Insight mobile application.

Q. Has the Company considered the impact the energy bridge device charge will have on participation in the DTE Insight program?

A. Yes. In late 2017, the Company initiated work to transition to a more robust and reliable mobile app platform. This new version of the app has been designed to provide an improved customer experience. As of March 2018, the Company tested the new platform and messages with a small number of customers, about 1,200, before asking the remaining customers to transition to the new app. These customers accepted the new app terms and conditions, will go through a six-month free trial and then begin to receive a charge in the latter part of 2018. Based on the initial test results, the Company expects the new platform, coupled with the newer generation of energy bridge devices, to deliver sufficient customer value to support the device charge and help manage any negative impacts on program participation due to the initiation of charges. The new app platform became available to customers in May 2018. Efforts to move all customers to the new platform will continue through 2018. Toward the end of 2018, the Company will study the impact on program metrics to guide a final customer charging approach beyond 2018 and will update its participation forecast.

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Q: How will the new DTE Insight app platform help with program participant's engagement?

A: New features available in the new app platform that the Company expects will contribute to improved participant engagement include:

- An improved energy bridge installation customer experience that leverages Bluetooth technology (included only in the newer generation of energy bridge devices)
- Terms and conditions related to the device charge that must be accepted in the app before an energy bridge is approved for shipping and which are expected to reduce the number of customers asking for the energy bridge and then not actually using the energy bridge
- Usage disaggregation displayed on the app dial showing separately "always on" usage. "Always on" usage is usage from devices that are always plugged in to the power source, such as computers, cable boxes, internet routers, game consoles, etc.
- A robust platform that can better facilitate the introduction of new functions to be released in the future to keep customers engaged and motivated to continue logging into the app for information

Q. What are the Company's planned efforts with respect to the DTE Insight program going forward?

A. In 2018, the priority is to finish the transition work to the new app platform. The Company will also continue to improve on its marketing and communications campaigns to support the move to the new platform and to encourage deeper customer engagement.

The Company began migrating all other customers to the new app platform in May of 2018 and ramped up its marketing efforts. All customers migrating from the old platform to the new platform have been asked to accept the new terms and conditions if they want to keep or receive the energy bridge device. All new customers will be directed to the new platform and must accept terms and conditions before receiving the energy bridge.

Q. Based on these plans, what is the forecasted number of energy bridge purchases required?

A. Based on 2018 beginning inventory, expected returns, and forecasted demand for new shipments (including the bridge period and the projected test year) the Company only expects to purchase approximately 20,000 additional devices through the end of the projected test year. The Company slowed down its marketing efforts at the end of 2017 and the beginning of 2018 and ramped back up its efforts in May 2018 after launching the new app platform. This resulted in a beginning inventory for year 2018 of approximately 52,600 units (see Figure 5 above, cumulative purchased less cumulative shipped plus cumulative returned). Forecasted returns for the projected test year are estimated at 7,400 units. These units will then be refurbished and put back in inventory to fulfill new requests. Energy bridge device demand was minimal between January and April 2018 while marketing was scaled back; is forecasted at approximately 34,000 from May 2018 to April 2019; and is forecasted at approximately 41,000 from May 2019 to April 2020. These movements in inventory would leave the Company with approximately 5,000 units in inventory by April 30, 2020. In order to continue expanding the DTE Insight program, the Company is planning to spend $1.0 million during the bridge period January 2018 through April 2019 and $2.9 million for projected

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test year period ending April 30, 2020 for the DTE Insight program. Please, refer to the Exhibit A-12, Schedule B5.6, page 1 of 2, line 5, column (e) and (f), for the total capital expenditure request.

<u>Other Demand Side Management Programs</u>

Q. Is the Company planning to implement any additional Demand Side Management programs?

A. Yes. The Company plans to implement multiple demand side management pilots, including the expansion and refinement of an existing Bring Your Own Device (BYOD) pilot and multiple new pilots that involve storage technologies. In order to implement these pilot programs, the Company is forecasting to spend $2.6 million during the bridge period January 2018 through April 2019 and $3.7 million for projected test year period ending April 30, 2020 for the Other DSM programs. Please, refer to the Exhibit A-12, Schedule B5.6, page 1 of 2, line 3, column (e) and (f), for the total capital expenditure request for other DSM programs.

Q. What was the initial design of the Company's BYOD pilot program as launched in 2017?

A. The Company enrolled approximately 200 customers in a BYOD pilot program in the fall of 2017. The Company provided customers with a $50 incentive to enroll in the program and have their thermostats configured to allow the Company to send a control signal during BYOD events up to 5 times a year. During a BYOD event, the Company sends a pricing signal to BYOD thermostats to raise the set-point by 4 degrees between 3 PM and 7 PM, Monday through Friday. BYOD customers are notified a day prior to a scheduled BYOD event so that these customers have the opportunity to make

additional behavioral changes, such as delaying the dishwasher or washing machine to run during off-peak times.

Q. What have been the initial results of the Company's BYOD pilot?

A. The customers in the 2017 pilot were on the standard D1 Residential tariff and their usage was compared against customers on the Dynamic Peak Pricing rate. The Company's measurement and verification results indicate that customers enrolled in the BYOD program reduced their peak load by 20% during BYOD events. The average per customer reduction was 0.7 kW across all 3 events that occurred in fall 2017. This value is higher than the Company's projected (or estimated) impact of 0.5 kW per customer as proposed in Case U-18419. This includes the impacts of average customer participation per event of 76% across all 3 events, meaning that 76% of the enrolled customers did not manually over-ride the utility initiated thermostat control set-point change. The representative data below shows that in a peak event, where the BYOD program is called upon by the Company, the participating BYOD customers show a steep decline in usage during the critical hours of the event when compared to DPP-only customers on a non-DPP event day. Figure 6 is actual event day data from September 26, 2017 for the BYOD pilot customers compared to DPP only customers.

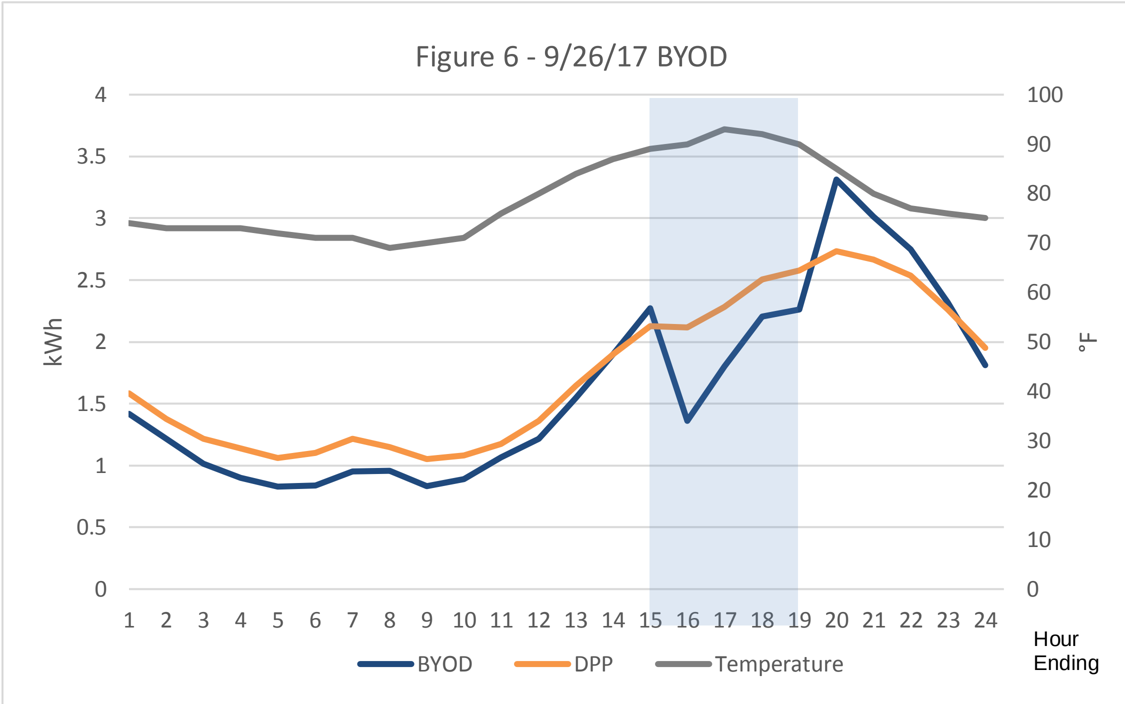

Figure 6 - 9/26/17 BYOD

Q. What are the Company's plans for the BYOD pilot program going forward?

A. The Company plans to refine and expand the BYOD pilot that started in 2017 with the funding approved in rates in Case U-18255 under the category of "Other DSM". As the pilot continues, the Company will seek to better understand factors that drive initial customer enrollment in such a program and re-enrollment in subsequent years. The company will also seek to validate performance during BYOD events with a larger set of customers, to better forecast how often customers may over-ride the Company's thermostat set-point changes under various circumstances and also how much peak load reduction occurs during BYOD events under various circumstances. While the 2017 performance results were higher than originally forecast, the Company recognizes that these results are based on a small 200-customer pilot. The Company does not intend to make significant changes to the forecasted value of the BYOD program until such time that a statistically significant number of devices have been deployed and additional BYOD event measurement and verification has occurred. The Company will request funding for expansion of the BYOD program in future rate cases as needed.

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Q. What are the proposed additional demand side management pilot programs?

A. The Company has currently identified additional pilot programs centered around Energy Storage options. The first two pilots would be behind the meter projects with Commercial and Industrial (C&I) customers to understand the actual operation and performance of batteries in the field and the impact on customer load, the ability to peak shave, and the reliability of the battery system. The Company is investigating 2 approaches, with one pilot installation designed to offset the manufacturing class peak hours between 11 AM and 3 PM and the second pilot installation focusing on the overall system peak hours between 3 PM and 7 PM. The third pilot is a proposed Non-Wires Solution (NWS) using a customer sited and utility controlled storage solution to potentially defer investment in substation equipment by dispatching the storage unit as needed. It should be noted that these customer-sited storage pilots funded as "Other DSM" are separate from the storage pilots discussed by Witness Bruzzano that will be sited at company owned facilities or properties. While information and lessons learned will be shared and the two teams will collaborate, the funding requests are separate.

Q. What is the expected timing associated with the Energy Storage DSM pilot programs?

A. Existing funding within the current Other DSM programs will be used throughout the bridge period of January 2018 through April 2019 to develop customer specific site information, battery size, battery chemistry and use case options, such as customer demand reduction, energy abatement, and an assessment of options to use storage plus renewables to provide a more consistent generation profile. The Company also plans to find customer locations for these pilots throughout 2018 and perform needed site investigation work. The funding requested for the projected test year will be for the

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purchase of the physical assets and installation costs upon program approval. The procurement of the hardware and installation would begin in late 2019, assuming approval of the requested funds in rates, to begin operation by the summer of 2020.

Q. What are the Company's planned efforts to develop and manage the DSM pilots?

A. The Company aims to remain flexible enough to efficiently redeploy DSM pilot spending and resources as capacity needs or other more cost-effective technologies arise in the near future. DTE Electric will be well positioned to expand existing or future programs to respond to changing capacity market conditions. With these objectives as goals, the Company will continue to evaluate other alternative DSM programs that may emerge as a result of insights from pilot programs or utility benchmarking efforts. In the coming years, the Company expects to continue developing new DSM programs that may become economic alternatives to generation capacity, have an appropriate level of customer adoption potential, and are cost-effective for the Company's customers.

Q. Does the Company intend to keep the MPSC apprised of the results of the Demand Side Management programs and capital expenditures approved in U-18255?

A. Yes. The Company fully intends to provide DSM updates and comply with all reporting requirements as part of the Commission's adoption of Staff's three phased approach for DSM programs in Case No. U-18369 on September 15, 2017. The Company will file a full reconciliation report on all expenditures approved in Case No. U-18255 by April 30, 2019 detailing customer participation and demand reductions.

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Part II: River Rouge Unit 3 NPVRR Analysis

Q. Has the Company completed an economic analysis regarding continued operations of Unit 3 at the River Rouge Power Plant?

A. Yes. In the recent Order in Case No. U-18255 issued April 18, 2018, the Commission did not agree that the Company's strategic evaluation and resulting conclusion to maintain the planned 2020 retirement date for River Rouge Unit 3 (RR Unit 3) represented adequate support for the Company's requested level of O&M and capital expenditures to maintain operations at RR Unit 3. The MPSC instead indicated that a Net Present Value of Revenue Requirement (NPVRR) analyzing RR Unit 3 was required to provide sufficient support for recovery of expenditures to maintain operations at RR Unit 3. While the Company believes that continued operation of RR Unit 3 through May 2020 was and remains justified based on its obligations to provide sufficient and reliable generation supplies to its customers, the Company has completed such an NPVRR analysis, the results of which are summarized on Exhibit A-12, Schedule B6.

Q. How did the Company structure its NPVRR analysis?

A. The NPVRR analysis of the RR Unit 3 consisted of two options:

1. Operate RR Unit 3 until the planned retirement date in May 2020
2. Retiring RR Unit 3 as soon as practical which is December 31, 2018, after the Company complies with the required retirement request filing process with MISO

For this evaluation, the Company assessed the incremental benefits and costs for both options, and calculated the net difference between the NPVRR of each option. A net positive difference indicates that the NPVRR associated with operating the RR Unit 3 through 2020 is more costly to customers; conversely, a net negative difference

indicates that the NPVRR of operating the RR Unit 3 through 2020 is less costly to customers. It should be noted that the difference in retirement dates between the two options is only seventeen months.

A total of three NPVRR sensitivities were examined, as shown in Exhibits A-12, Schedule B6 page 2 of 5. In each sensitivity, both retirement options incorporate the incremental benefits and costs of specific value components. On pages 3-5 of that same exhibit, the total benefit and cost of each component for each option is summarized in line 4-5, columns (b) through (g) with the total and overall NPVRR listed in column (h) line 6. Line 7, columns (b) through (j) list each year and line 10-15, column (a) provides the value components that are included: operation and maintenance (O&M) expense, fuel costs, energy and capacity purchases, capital investment and property tax expense. The resulting net difference between the NPVRR of each component is listed in column (k) and summed up in line 16.

Each NPVRR evaluation considered assumptions listed on Exhibit A-12, Schedule B6, page 1 of 5. The assumptions for this analysis have been assessed by the respective subject matter experts in the Company's Generation Optimization, Fossil Generation, Tax and Business Planning and Development departments.

Q. What sensitivities did the Company perform regarding the inputs for the NPVRR analysis?

A. The Company performed sensitivity calculations for the capacity price input in the NPVRR analysis. For the capacity purchases in the case of necessary capacity replacement for the option of retiring the unit in 2018, the Company considered a range

of pricing alternatives that go from a low forecast of capacity prices based on modeling conducted by PACE Global[1], an energy industry consulting firm, to the Cost of New Entry (CONE) at $90.7 / kW-year. As stated in the answer above, an NPVRR evaluation was conducted for each capacity price value and the results were examined. A summary of the sensitivities for the analyses is shown in Exhibit A-12, Schedule B6, page 2 of 5.

Q. What are the results of the NPVRR analyses performed for RR Unit 3?

A. The results of the NPVRR analyses for RR Unit 3 show a range of net present value outcomes consistent with the selected capacity price. The NPVRR results in Exhibit A-12, Schedule B6, page 2 of 5, column (c) range from $15 million more costly to $10 million less costly to customers to maintain the planned 2020 unit retirement date. Column (b) present the three sensitivities for different capacity prices. A more detailed NPVRR summary for each capacity price sensitivity can be found in Exhibits A-12, Schedule B6, page 3-5 of 5.

Q. What factors has the Company taken into consideration in its decision-making process regarding the timing of the retirement of RR Unit 3?

A. An economic cost and benefit analysis can provide a general guideline for the reasonableness and prudency of continued operations of a generating unit, although there are several other factors that need to be considered. As Company Witness Mr. Paul indicates in his direct testimony, there are several additional factors to consider when determining whether a generating unit should be retired. Witness Paul discusses the Company's conclusion that the best option is to continue operating RR Unit 3 until its planned retirement date of May 2020.

[1] Pace Global, a Siemens business

Q. Has the Company completed similar NPVRR analyses regarding the continued operations of the remaining Tier 2 units?

A. No. The Order issued in MPSC Case No. U-18419 dated April 27, 2018, p. 48-49 concluded that "[t]he Commission agrees with DTE Electric that, although there is a possibility that one or more of the Tier 2 units might retire early, any plans to do so should await the outcome of the Company's 2019 Integrated Resource Plan (IRP) analysis and the results of MISO's Attachment Y reliability study…". DTE Electric has been assigned the date of March 29, 2019 to file an IRP pursuant to MCL 460.6t. The Company will conduct such an analysis in the planned IRP, consistent with recently issued MPSC guidance. The Michigan Integrated Resource Planning Parameters presented in Case No. U-18418 describe compliance guidelines for utilities for future IRP's and/or Certificate of Necessity proceedings. Under Scenario 2, the Commission states "Company-owned resources retirements may be defined by the utility…coal units owned by the utility that are not explicitly assumed to retire during the study period shall be allowed to retire in the model based upon economics". The Company will make decisions on the timing of retirement of units based on economics as well as other planning principles that include flexibility and reliability.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

REBUTTAL TESTIMONY

OF

IRENE M. DIMITRY

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF IRENE M. DIMITRY

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Q. What is your name, business address and by whom are you employed?

A. Irene M. Dimitry, Vice President of Business Planning & Development, One Energy Plaza, Detroit, Michigan, 48226. I am employed by DTE Energy Corporate Services, LLC, a subsidiary of DTE Energy.

Q. Did you file direct testimony in this proceeding on behalf of DTE Electric Company (DTE Electric or Company)?

A. Yes, I did.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is as follows:

- Respond to the recommendation by MEC-NRDC-SC (MEC) Witness Allison to disallow rate recovery of any future capital costs and fixed operations and maintenance (O&M) expense at River Rouge Unit 3 (RR3) [Allison, page 6, lines 25-27];
- Respond to MEC Witness Allison's recommendation to disallow rate recovery of any future capital costs at St. Clair Units 1, 2, 3, and 6 [Allison, page 7, lines 2-3];
- Address MEC Witness Allison's historical economic evaluation of the Company's fleet of coal generation units;
- Respond to Staff Witness Matthews' proposed disallowance of $9.6 million in capital expenditures intended to fund the Programable Controllable Thermostat (PCT) program [Matthews, page 7, lines 14-16] and propose a tariff rate modification to improve customer enrollment in the PCT program; and
- Address Staff Witness Matthews' recommendations regarding performance goals for the Demand Response (DR) plan [Matthews, page 11, lines 11-12].

The absence of a discussion of other matters in my testimony should not be taken as an indication that I agree with all other aspects of intervenor testimony. The narrow focus of my testimony is instead, a consequence of focusing on priority issues.

Q. Are you sponsoring any rebuttal exhibits?
A. No, I am not.

CAPITAL AND O&M INVESTMENT AT RIVER ROUGE UNIT 3

Q. Do you have concerns about Witness Allison's testimony?
A. Yes, I do. I disagree with Witness Allison's recommendation to disallow rate recovery of any future capital costs and fixed O&M expense at RR3 which appears to be primarily based on his conclusions regarding the economics of what he considers to be the most likely scenario, while essentially dismissing other factors including resource adequacy, local community impacts and workforce planning issues. In my rebuttal, I will address several assertions of Witness Allison regarding economic assumptions, while Company Witness Paul will address additional factors that should be taken into consideration, including concerns about reliability. Company Witness Arnold also addresses why it is inappropriate to dismiss resource adequacy concerns when contemplating early retirement of the Company's Tier 2 generating units.

Q. Do you support the range of capacity price sensitivities the Company assessed during the RR3 economic analysis?
A. Yes. The Company assessed multiple capacity price sensitivities including both low and high value assumptions in its Net Present Value of Revenue Requirement

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("NPVRR") economic analysis. The low end of the range of capacity prices used at the time of the filing was the June PACE capacity prices for planning year 2018/2019 at $3.65 per kW-year and $1.50 per kw-year at 2019/2020. Given uncertainty about the future and consistent with past practices, the Cost of New Entry (CONE) is an alternative sensitivity that assesses the highest possible clearing price if an early retirement is the cause of MISO Zone 7 not meeting the Local Clearing Requirement. The middle range sensitivity reflected 50% of CONE. These sensitivities capture the range of uncertainty with capacity prices.

Q. Did you consider a lower capacity price other than the June PACE capacity prices?

A. No. The June forecast provided by PACE already represented a relatively low forecast of capacity prices, for planning year 2018/2019 at $3.65 per kW-year and $1.50 per kw-year at 2019/2020. Using those capacity prices, the total cost of purchasing capacity to offset the early retirement of RR3 is less than $1M, as shown on Exhibit A-12, Schedule B.6, page 3 of 5, line 30, of my direct testimony. Adding an even lower capacity price to the range of alternatives would most likely be immaterial.

Q. What are your thoughts with regard to Witness Allison's claim that "the only way one might reasonably conclude that the NPVRR analysis results support the continued operation of River Rouge Unit 3 is if one believed that the 100% CONE capacity price sensitivity is the most likely scenario" [Allison, page 15, lines 2-5]?

A. I disagree. The CONE sensitivity represents an upper boundary for capacity prices in MISO, while the 50% CONE represents a very reasonable middle range sensitivity,

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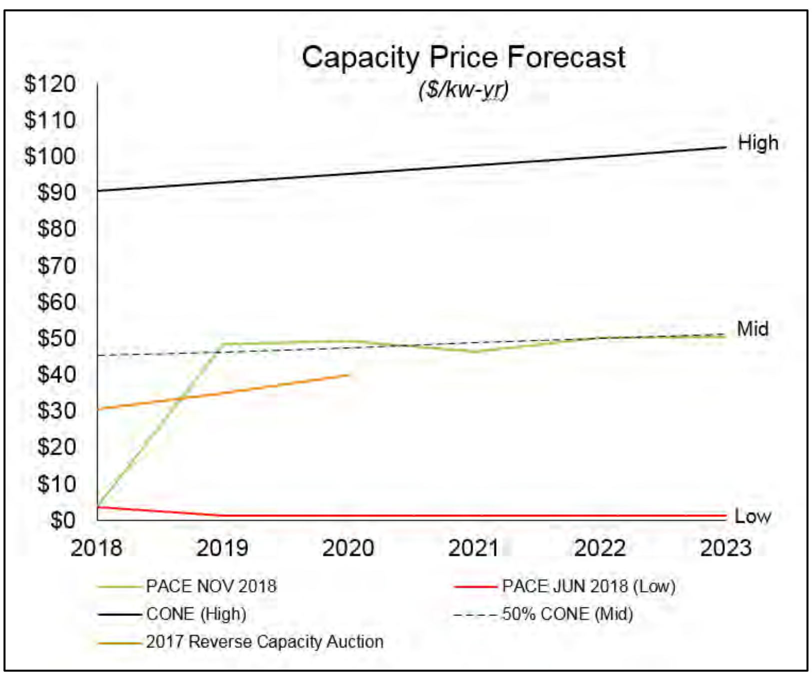
and the Company's lower end sensitivity used a capacity price forecast from PACE that was the most recently available at that time. Figure 1 below shows all three capacity price sensitivities used in the Company's RR3 NPVRR analysis, as well as the average price the Company paid during the 2017 reverse auction and the most recent PACE forecast received by the Company in November 2018. Actual prices paid by the Company in 2017 closely compare to 50% CONE, which supports the reasonableness of this sensitivity. Witness Allison himself supports the use of 50% CONE as a sensitivity in his analysis [Allison, page 9, lines 13-15]. Finally, the most recent November 2018 capacity price forecast from PACE is very close to the 50% CONE sensitivity used for the RR3 NPVRR analysis, contrary to Witness Allison's claims that a 50% CONE sensitivity "represents another high-end price sensitivity" [Allison, page 17, lines 23-24] and "does not present a most likely estimate" [Allison, page 17, lines 12-13].

<u>Figure 1</u>



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Q. What are your thoughts with regards to Witness Allison's focus on the "most likely" scenario when considering early retirement of RR3?

A. I disagree with that approach. Witness Allison deems the PACE capacity price forecast used in the RR3 NPVRR analysis to be the Company's base forecast [Allison, page 16, lines 5-6]. He then goes on to say that the Company "believes or ought to believe" that the sensitivity using this forecast "represents a most likely scenario" [Allison, page 19, lines 5-6]. Witness Allison appears to make these claims based on the frequency with which the Company has utilized PACE forecasts in other proceedings [Allison, pages 15-16]. The fact that the most recent capacity price forecast (November 2018) from PACE is quite different from the PACE forecast (June 2018) used in the Company's RR3 NPVRR analysis (as shown above in Figure 1) supports the Company's position that a full range of sensitivities should be considered when contemplating a significant decision like the possible early retirement of a power plant or generating unit. Markets, facts, and forecasts change over time and what appears "most likely" at one point in time may not in fact turn out to be the most pertinent forecast. Witness Allison's focus on the "most likely scenario" and his dismissal of the other sensitivities is flawed and is not a reasonable and prudent basis for making important power plant retirement decisions.

Q. Does the range of NPVRR sensitivities presented by the Company in this case support continued operations of RR3?

A. Yes. As I highlighted in my direct testimony, the sensitivities considered within the RR3 NPVRR analysis yielded results that showed a range of outcomes from $15 million more costly to $10 million less costly to customers to maintain the planned 2020 retirement date for RR3. I firmly believe this range of sensitivity outcomes

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supports continued operation of River Rouge Unit 3 as the most reasonable and prudent path given the non-economic factors discussed in more detail by Company Witness Paul. Economic analyses require assumptions about an uncertain future and it is reasonable and prudent to consider a range of outcomes rather than focus solely on what is presently perceived to be the "most likely scenario".

Q. Did the RR3 NPVRR analysis consider energy purchase costs in the 2020 retirement case, relative to a two month 2018 outage?

A. No. The Company acknowledged that the energy purchase costs associated with the 2018 outage of RR3 were not considered.

Q. Did Witness Allison modified DTE's RR3 NPVRR analysis to account for the energy purchases in the 2020 retirement case, relative to a two month 2018 outage?

A. Yes.

Q. How do you respond to Witness Allison's claim that "this error biases DTE's results in favor of continuing to operate River Rouge Unit 3" (page, 12, lines 5-6)?

A. I disagree with Witness Allison's characterizations and conclusions. As I explained in my direct testimony [Dimitry, page 30, lines 8-12], the results of the Company's NPVRR economic analysis were always presented as a range of outcomes consistent with the identified capacity prices. Witness Allison's adjustments to the Company's NPVRR, as presented in Table 5 on page 21 of his testimony, still yielded a mixed range of outcomes. Even if one gives credence to the concerns raised by Witness

Allison regarding the Company's NPVRR analysis, this is not evidence of bias because the Company's position regarding the retirement of RR3 is not exclusively based on economics. Given the mixed range of financial outcomes (even after Witness Allison's adjustments), the Company believes that the other non-economic considerations discussed by Witness Paul – including concerns about reliability – support continued operation of RR3 at this time, along with the requested nominal capital investments and O&M to ensure that such operations are maintained safely.

Q. What are your thoughts about plant retirement decisions and economic analysis?

A. Plant retirement decisions should not be based solely on economic analysis. Economic analysis can provide a general guideline regarding the reasonableness and prudency of continued operations of a generating unit but several other factors also need to be considered. And when economic analyses yield mixed or marginal outcomes – such as in this case where the Company's NPVRR analysis for retiring RR3 early (in advance of the planned retirement date) yielded somewhat favorable, neutral, and somewhat unfavorable financial outcomes – then non-economic factors become even more important. The MPSC Staff recently reinforced this point of view in case U-20165. In that case, related to a retirement analysis for two of Consumers Energy's coal plants, the MPSC Staff concluded that Consumers' analysis showed that the retirement decision was neither overwhelmingly attractive nor particularly risky, and thus the plant retirement decision "comes down largely to a qualitative policy decision rather than an overwhelming quantitative decision." [Heidemann, page 17, lines 16-19]. Staff's testimony concisely summarizes my point – it would not be reasonable or prudent to make long-term decisions regarding capital-intensive assets every time an economic analysis suggests a shift in value.

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Q. Are there other non-economic factors that should be considered in the decision of continuing to operate RR3?

A. As discussed in the rebuttal testimony of Company Witness Paul, there are important factors such as MISO grid reliability, resource adequacy, local community impacts, and workforce planning that are important in determining the reasonableness and prudency of continued operations of a particular generating unit. Company Witness Arnold also discusses how the Company's Tier 2 units' support capacity-related reliability needs.

Q. What has the MPSC indicated regarding the early retirement of the Company's Tier 2 generating units?

A. In its April 27, 2018 order in Case U-18419, the MPSC addressed the Company's plans for retiring its Tier 2 units (which include RR3) and reached the following conclusions:

- "The Commission agrees, therefore, that the most reasonable and prudent course of action is to retire the Tier 2 units by 2023 as DTE Electric proposes." [Page 47]
- "The Commission agrees with DTE Electric that, although there is a possibility that one or more Tier 2 units might retire early, any plans to do so should await the outcome of the Company's 2019 IRP analysis and the results of MISO's Attachment Y reliability study." [Pages 48-49]
- "Other matters such as workforce and local government tax impacts may also be considered in a decision of this magnitude." [Page 49]
- "As discussed further in this order, the Commission observes the "power need" may also entail the need for local voltage support and other reliability benefits to address the closing of numerous coal plants and integration of other resources such

as wind and solar energy." [Page 49]

Thus, in the Commission's order in Case U-18419 issued just 6 months ago, the Commission agreed that, for now, the Company's Tier 2 power plants should be retired as proposed by DTE Electric; that any early retirements of Tier 2 units should await the outcome of the Company's 2019 IRP; and that non-economic factors such as workforce impact, community impacts, and reliability may be considered when contemplating an early retirement of Tier 2 units such as RR3.

<u>CAPITAL INVESTMENT OF ST. CLAIR 1, 2, 3, AND 6 GENERATING UNITS</u>

Q. Do you have concerns about Witness Allison's testimony related to various St. Clair generation units?

A. Yes. I disagree with Witness Allison's recommendation to disallow rate recovery of any future capital costs at St. Clair Units 1, 2, 3, and 6 under the basic assertion that a "re-evaluation" of St. Clair units 6 and 7 "would have generated net benefits for DTE ratepayers" [Allison, page 27, lines 2-3] and that "evidence indicates that St. Clair Units 1, 2, and 3 are very likely less economic than Unit 6 and 7" [Allison, page 28, lines 3-4].

Q. Do you have any concerns about Witness Allison's approach in "reevaluating" the Company's prior NPVRR analysis related to its St. Clair generating units?

A. Witness Allison's conclusions are based on his adjustments to DTE's 2017 NPVRR analysis that focused only on St. Clair Units 6 and 7. The Company's analysis at that time supported continued operations of all St. Clair units until their planned retirement dates in 2022 and 2023. It is inappropriate to retroactively apply new capacity forecasts to an older analysis of just two generating units, extrapolate those

conclusions to additional generating units, and then suggest the results provide sufficient support to now recommend early retirement of St. Clair Units 1, 2, 3, and 6 or to recommend disallowance of the requested capital that is necessary to safely maintain operations of these generating units. The decision to retire a generating unit or plant earlier than planned requires diligent analysis using comprehensive and internally consistent data, and must be supported with specific reliability studies under MISO's Attachment Y process, as discussed by Witness Paul and as cited above in the Commission's April 27, 2018 order in Case U-18419. Until and unless such a comprehensive study is completed – as is planned within the Company's 2019 IRP -- it is reasonable and prudent for the MPSC to support recovery of continued capital and O&M investments to ensure the safe continued operations of St. Clair Units 1, 2, 3, and 6 through to their proposed retirement dates.

Q. Will DTE Electric be conducting an updated economic analysis regarding continued operations of its coal units?

A. Yes. Such an analysis is already planned for the Company's March 2019 Integrated Resource Plan (IRP) filing. DTE Electric has been assigned the date of March 29, 2019 to file an IRP pursuant to MCL 460.6t. The Company will conduct such an analysis in the planned IRP, consistent with recently issued MPSC guidance. The Michigan Integrated Resource Planning Parameters presented in Case No. U-18418 describe compliance guidelines for utilities for future IRPs and/or Certificate of Necessity proceedings. The Company will make decisions on the timing of retirement of units based on economics as well as other planning principles that include flexibility, reliability, and community impacts.

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ECONOMIC EVALUATION OF COAL UNITS

Q. Do you have additional concerns about Witness Allison testimony?

A. Yes, I do. I disagree with Witness Allison's conclusion "that DTE is unnecessarily continuing to maintain and operate uneconomic coal units" [Allison, page 6, lines 18-19]. Witness Allison presents a list of economic assumptions as the basis for his conclusion, including Table 1 on page 7 of his testimony, which purports to calculate historical net revenues of Tier 2 coal plants from 2015-2017. He also presents a similar analysis for Tier 1 plants in Table 3 on page 10.

While economic analysis can provide a general guideline for the reasonableness and prudency of continued operations of a generating unit, several qualitative factors also need to be considered as already discussed above. Furthermore, historical data from 2015-2017 is not relevant today, in 2018, when contemplating early retirement of generating units or determining investments required to ensure continued safe and reliable operations of the generating units. The economic factors to consider in such a decision should be based on going forward estimates of costs to operate and maintain those units compared to estimates of costs to retire those units and replace their energy and capacity. The calculations presented by Witness Allison related to the Company's generating units are not a sufficient basis for making a complex decision such as deciding whether to retire the Company's generating units earlier than planned or whether it is deemed necessary to continued capital and O&M investments to ensure the safe continued operations of generating units.

DEMAND RESPONSE PROGRAMS

PROGRAMMABLE CONTROLLABLE THERMOSTAT PROGRAM

Q. What is Staff Witness Matthews' general opinion regarding the outlook of DTE Electric's demand response programs?

A. Witness Matthews is supportive of the Company's Demand Response (DR) efforts, and believes that the proposed programs, which include the Programmable Controllable Thermostat (PCT) program, can have a multitude of benefits for both customers and the Company. However, Witness Matthews indicates that a cautious approach to demand response should be taken to ensure that the benefits of the programs are realized before existing programs are expanded [Matthews, page 7, lines 7-11].

Q. Do you share Staff Witness Matthews' opinion regarding the outlook of DTE Electric's DR efforts, which include the PCT program?

A. I do concur with Witness Matthews' positive view that is supportive of DTE Electric's DR efforts, which include the PCT program. DR programs can represent viable alternatives within the Company's resource portfolio to continue providing secure, reliable, and sustainable energy supply to the Company's customers. A more specific purpose of the PCT program is to reduce the impact of residential load on peak demand, thus lowering the Company's need to obtain additional generation capacity and improving customer affordability.

Q. Staff Witness Revere recommends an adjustment to tariff D1.8 as a way to improve customer engagement. Do you support the recommended tariff adjustment?

A. Yes. Customers who enroll in the PCT program are also enrolling on the D1.8 tariff rate. Under this tariff, the maximum number of DPP events that can be called are twenty (20) with 4-hour on-peak periods for a total of no more than 80 hours per year. The Company agrees that the high number of possible events may be a deterrent to customer interest in the rate which ultimately affects enrollment in the PCT program. The Company agrees with the recommendation of Staff Witness Revere, as described on page 9 of his direct testimony, that the number of events be reduced to fourteen (14) with 4-hour on-peak periods for a total of no more than 56 hours per year.

Q. Does Staff Witness Matthews' make additional specific recommendations regarding the PCT program?

A. Yes. Witness Matthews is recommending the disallowance of $9.6 million for the proposed PCT program encompassing the capital expenditures allocated for the period starting on January 1, 2018 and ending on April 30, 2020, which includes both the projected bridge period (January 1, 2018 – April 30, 2019) and the projected test year (May 1, 2019 – April 30, 2020). Witness Matthews contends that the Company has not demonstrated that the program has been successful enough in the initial stages to merit the support of capital expenditures to fund additional PCT units beyond the initial 10,000 units approved in Case No. U-18014. Witness Matthews indicates that the Company has not completed its enrollment goals from prior rate cases and pushed its enrollment forecast to later years. Therefore, Witness Matthews argues that the Company needs to first show a commitment to enroll enough customers to utilize the

initial 10,000 PCTs previously approved in rate cases before the Commission approves any additional PCTs [Matthews, page 9, lines 1 – 3].

Q. What is your response to the proposed disallowance?

A. I disagree. I believe the Company's requested funding for the PCT program is justified by the progress and success achieved in implementing the initial phases of this pilot program. Throughout the year 2018, the Company has demonstrated a commitment to market the program and enroll customers as they respond to the various marketing campaigns and outreach efforts. The marketing and outreach efforts include specific campaigns through a wide range of social and digital media, mail and specific community outreach. The Company's activities also include the purchase of equipment, as well as adequate software capability, specifically the Distributed Energy Resource Management System (DERMS), to execute IT integration and program implementation.

Q. Are there any other additional indicators in the initial stages of the Company's PCT program?

A. Yes, there are other indicators of PCT program success. During the summer of 2018, the Company called four (4) events, which involved increasing the temperature set-point of activated customer PCT units by 4 degrees. The number of customer PCT units involved in these events ranged from 883 units on June 28, 2018 to 1,597 units on August 28, 2018. Representative data indicated that in a called event, the PCT customers show a meaningful decline in electricity usage in the critical hours of the event. The Company has measured an average reduction of 1.05 kW per participating customer during these recent events.

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Q. What are your thoughts concerning the customer enrollments to date in the PCT program?

A. I think the level of customer enrollments to date is consistent with a finding of success in the initial stages of this pilot program. Customer enrollments to-date in the PCT program have been sufficient for the Company to remain committed to achieving 17,000 enrollments by early 2020. As indicated on page 5 of Witness Matthews' exhibit S-12.3, the Company has enrolled approximately 3,000 customers as of September 30, 2018, a number that has increased to approximately 3,900 customers as of November 12, 2018, and in line with the revised forecast to enroll 4,500 customers by December 31, 2018. Although the Company has revised its original forecast for December 2018 from 7,000 to 4,500 customers, the Company has not changed its commitment to achieve a goal of 17,000 unit-enrollments by April 30, 2020 as originally indicated on page 12 of my direct testimony.

Q. Should customer enrollments be the sole indicator of initial success of a DR program such as the PCT program?

A. No. DR programs are dependent on both the Company's actions and also the customers' willingness to participate in the program. This was recognized in the DR framework approved in Case No. U-18639 and also by Witness Matthews in his testimony on page 11. To date in this pilot, a significant focus of the Company has been on program launch and development, including initial marketing campaigns to recruit customers. Initial customer enrollments are not necessarily indicative of long-term program success. As with any customer-focused program, it should be expected that target marketing will be refined over time as results of initial campaigns are assessed. Lessons learned from initial marketing efforts are already being

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incorporated in new campaigns to drive increased future customer engagement, subsequent enrollment, and event participation as the program matures over time.

Q. Has the Company identified any trends in customer engagement levels in other DR programs or pilots?

A. Yes, we have noted recent positive customer engagement trends. The Bring Your Own Device (BYOD) pilot program, described on pages 23-25 of my direct testimony, has recently shown positive levels of customer engagement. The BYOD pilot program has unique features but also shares some similarities with the PCT program. The targeted customers already have their own smart thermostat devices, are on the standard D1 Residential rate, and are entered in a sweepstakes for a chance to win one of ten $500 e-gift cards for enrollment. Similar to the PCT program, the Company sends a signal to the thermostats during specific events to increase the setpoint during on-peak times. The customer can adjust behavior and/or override the company's signal without any financial consequence. In 2018, the Company started the marketing campaign with a goal of 5,000 customers total in a 3-year period ending in 2021. Customer response has been very positive. Enrollments already reached 3,620 from August 28, 2018 to November 12, 2018, reaching the forecasted targets through 2020 in a matter of 6 weeks. The pilot tests in the events called during 2018 showed an average demand reduction within the projected impact of 0.5 kW per customer, and an average peak demand reduction of 0.85 kW per customer. The Company is monitoring ongoing results, and potentially, aims at expanding enrollment, and increasing customer engagement that can result in effective peak demand reduction throughout 2019 and beyond.

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Q. How do you respond to Witness Matthews' recommendation for specific performance goals for the DR programs?

A. I only agree in part. I agree with Witness Matthews' recommendation that performance goals for Demand Response be included as an essential element of a DR plan. Those performance goals may include goals such as expected demand reduction, capital and O&M associated costs. However, key performance goals should be established and evaluated at the total DR plan or portfolio level.

It should be noted that the ultimate purpose of the Company's DR plan is to help reduce customer's energy use during peak hours, providing value to the Company's total customer base through potentially lower capacity costs and potentially offsetting the need for future generation resources. In recognition of these overall goals, a well-run DR plan should include the flexibility necessary to find the best combined portfolio to serve customers and be measured accordingly. Therefore, the Company could support performance goals that are related to achieving planned capital investments and O&M costs consistent with its DR plan and also goals related to reduced demand resulting from its full set of DR programs. However, certain metrics such as customer enrollment, installation, or participation may be identified specifically for some of the pilots, programs or tariff-based rates as a way to track progress in launching a program, rather than to measure the overall success or effectiveness of a particular program.

I do agree with Witness Matthews' statement that as companies learn more about DR programs, the goals may need to be reviewed and adjusted on an on-going basis. Future DR plan review processes, including reconciliation procedures, could serve

well as a process to adjust, fine-tune and modify the goals of the DR plan and its specific programs for the maximum potential customer benefit.

Q. What are your thoughts on Witness Matthews' recommendation for the specific performance goals for the DR programs in this case?

A. Here again, I agree only in part. I do agree with the overall recommendation stated by Witness Matthews regarding the need to determine a set of performance goals, but I disagree with the specific set of performance goals indicated by Witness Matthews and I recommend that further analysis and investigation is needed to determine the right set of metrics.

Furthermore, Witness Matthews recommends that the Company's performance goals for the test year be based upon the Company's expected spending, less his recommended disallowance for PCTs, and peak MW reduction as found in his testimony's Exhibit S-12.3, page 6. As stated above, I believe that the Company has demonstrated sufficient success in the initial phases of the PCT pilot to support funding that Witness Matthews recommends disallowing. So in this regard, I disagree with Witness Matthews that any metric should include his proposed disallowance for PCTs.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

JUDGE WALLACE: And with that, Mr. Bzdok.

MR. BZDOK: Thank you, your Honor. As the first order of business, may we approach to distribute a packet of exhibits to everybody?

JUDGE WALLACE: You may.

MR. BZDOK: Thank you. So I will just note for the record that what is being handed out at this time, the Company has already received one, is marked as proposed Exhibits MEC-122 through MEC-133. Now, you'll note that on MEC-122, the top page, there is a stamp that says Confidential-subject to protective order, et cetera, et cetera. We have conferred with the Company and confirmed that the actual, this actual face of this document is not confidential, 122 is not confidential. Now, 123, which will be coming around in an envelope later as part of the confidential session, that is the attachment and that is confidential. So what we've handed out as really 122 and then 124 through 133 is a set of public proposed exhibits that we'll be discussing with the witness over the course of her exam. So that's the first point.

JUDGE WALLACE: O.K.

MR. BZDOK: And then the second point is that if everyone who has a packet would turn to Exhibit proposed 126, which is a color version of the Planning

Year 2018-19 Loss of Load Expectation Report and cross off 126 and write in 135, because that's an item that was admitted in the last exam. When we originally set this up, Mr. Arnold was going to be going after Ms. Dimitry, and then there was a change in the witness order, and so we're just making some adjustments. So in our packet it's just a color version of 135 that was already admitted as 126. Does that make sense? I probably have confused everybody at this point.

JUDGE WALLACE: O.K. Are we admitting both?

MR. BZDOK: No.

JUDGE WALLACE: So 126 is admitted?

MR. BZDOK: 126 is --

JUDGE WALLACE: Or will be admitted?

MR. BZDOK: 126 is gone --

JUDGE WALLACE: Is exactly this?

MR. BZDOK: Will not be offered. What we have marked as 126 has been admitted already as 135 --

JUDGE WALLACE: Got it.

MR. BZDOK: -- but it's just convenient to not pull it out of here, and this is a color copy which I think is preferable anyway.

JUDGE WALLACE: So we're looking at Exhibits 122, 124, 125, 135, which has already been

admitted, and then 127, 128, 129, 130, 131, 132, and 133. O.K. Do you want to -- let's move for admission when it's appropriate. Do you want to move for admission of all these now?

MR. BZDOK: No, I don't. We will discuss them and we will offer some of them and not others. The whole point of this was if we were going to offer like a dozen documents, that we do it in a way that would be as time streamlined as possible.

JUDGE WALLACE: O.K.

MR. BZDOK: So that's the reason for the packet. We have a couple others that may come up during the course of an exam, and we'll distribute those and offer them separately.

JUDGE WALLACE: O.K.

MR. BZDOK: So thanks for that indulgence there procedurally.

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(Documents distributed and marked for identification by the Court Reporter as Exhibit Nos. MEC-122, MEC-124, MEC-125, MEC-127 through MEC-133.)

CROSS-EXAMINATION

BY MR. BZDOK:

Q Good afternoon, Ms. Dimitry.

A Good afternoon.

Q I want to begin today by setting some context for where we are in terms of your direct testimony, some of our testimony, and your rebuttal testimony relative to River Rough Unit 3 plant or unit, O.K. So just as a brief recap, at a very general or high level, and you please, you know, correct me if I say anything incorrectly, but just to be efficient, this is the third case in which we've been talking about this plant and NPVs and economics of this plant in a row; would you agree?
A I believe so, yes.
Q Specifically Case 18014, which was two rate cases ago, Case 18255, which was the last rate case, and now this case, correct?
A Correct.
Q And generally speaking, in Case 18014, would you agree, and clarify if you wish to, that the Commission directed that DTE should do an updated net present value revenue requirements analysis for, or NPVRR analysis, of River Rouge 3 in order to support inclusion in rate base of projected capital expenditures for that unit?
A I don't remember exactly what it said two rate cases ago, I do remember we talked about it.
Q Generally speaking, there was some kind of a directive that was about doing an NPV or NPVRR analysis relative to River Rouge, correct?

MR. CHRISTINIDIS: Let me place an objection, your Honor, to the extent the question calls for a legal conclusion about what the Order required.

MR. BZDOK: So I appreciate the objection, and I will rephrase to the extent that I can, because that's not my interest here today.

Q (By Mr. Bzdok): So in -- you were a witness in 18014 and you were also a witness in 18255, correct?

A Correct.

Q And in 18255, you were a witness on issues that included this question of an NPV analysis for River Rouge, correct?

A Yes.

Q Do you prefer I refer to it as an NPV or an NPVRR or something else?

A Either is fine with me.

Q I'm going to call it NPV because that's just a little bit easier to get out. O.K.?

A O.K.

Q And in 18255, part of your testimony did address the Commission's directive or language from 18014 to the Company about River Rouge and NPV analyses, correct?

A So again, I don't remember exactly what the Commission said in 18014. My memory is that that -- we believed we needed to assess it, and I don't remember if it

specifically said you had to do an NPV. I think they said take a look at River Rouge and assess whether it should be retired early; that's what I remember.
Q That's all I'm asking you for is your memory. And then in your testimony, your direct testimony in 18255, again, just at a high level and generally to just put everybody on the same page, DTE conducted what I believe you referred to as a strategic analysis or a strategic assessment at that time relative to River Rouge, correct?
A Yes, --
Q And based --
A -- that's my memory.
Q Sorry.
A Yes, that's my memory.
Q And based on some determinations out of that analysis that had to do with reliability and/or resource adequacy, the Company concluded that it would not present in 18255 an NPV analysis of River Rouge Unit 3, correct?
A In 18255, we did not present an NPV, we said we did a strategic assessment and concluded continued operations made sense.
Q And then the Commission in its Order in 18255 directed the Company to do an NPV of River Rouge Unit 3, correct?
A I believe so. I don't remember exactly how they worded it.

Q And so I'm looking at your direct testimony, page 28. Maybe let's go there.
A O.K. Yes, I'm there.
Q So page 28, lines 4 to 11, you more or less recapped these same events, correct?
A Yes.
Q And so based on this recap of events, you would agree with me that the Commission determined that the strategic evaluation or assessment that was done was not sufficient to support the Company's requested expenditures on River Rouge Unit 3 and indicated that an NPV analysis was required to support recovery of those expenditures, agreed?
A Agreed.
Q O.K. And that is the reason why the Company has now presented an NPV analysis of River Rouge Unit 3 in this case, correct?
A Yes.
Q And you are the witness who sponsors that analysis, right?
A Yes.
Q As Exhibit A-12 Schedule B6, correct?
A Yes.
Q Now, I will make the representation to you the same as I made to Mr. Stanczak, which is that if I'm showing you

anything on the screen or referring to anything, that I have not modified what I received from the Company in any way and that you can rely on that. But this is, generally speaking, the analysis that we're referencing here up on the screen, A-12 Schedule B6, page 1 of 5?

A It looks like it. I can't really read it from here, but yes.

Q It looks familiar. O.K. Do you have it with you as well?

A I do.

Q O.K. I'm only providing it on the screen for the benefit of people who don't have in front of them, I'm not looking for you to pick out specific numbers off the screen. If you have it in front of you, we are going to discuss it, but we can discuss it off of the document that you have in front of you.

This analysis, as I understand it from the footnote at the bottom of page 1, was carried out about, on or about early June of 2018, correct?

A Correct.

Q I take that as of June 7 as it was completed by June 7?

A I believe that's correct.

Q And the analysis from page 1, it could be determined, and then -- let me try that again.

This analysis covered part of 2018, all

of 2019, and part of 2020, correct?
A This analysis compared two scenarios, one which was to retire River Rouge 3 at its planned date in 2020 and one which assumed that River Rouge would be retired at the end of 2018.
Q And the planned date for 2020 was May of 2020; is that correct?
A Yes.
Q O.K. And the analysis, generally speaking, used some assumptions from the year 2018, some assumptions relative to the year -- let me rephrase that question. O.K.
They used some assumptions relative to the year 2018, some assumptions relative to the year 2019, and some assumptions relative to the year 2020 or part thereof, correct?
A Yes. And there were additional years that were looked at.
Q What years were those?
A There were assumptions about ongoing costs after retirement.
Q Thank you for that clarification. Now, page 1 of the exhibit, which is also still on the screen, page 1, states the assumptions relative to this analysis, correct?
A The primary assumptions, yes.

Q Fair enough. And but not by way of an exclusive or exhaustive list, but those primary assumptions included assumptions about market energy prices, capacity prices, certain fixed expenses, and certain variable expenses; would you agree?
A Yes.
Q As to the -- now, looking specifically at this exhibit, lines more or less 9, 11, 13, and 14, those assumptions included three capacity price -- three capacity price scenarios or sensitivities; would you agree?
A Yes.
Q And those were -- those are listed here as a 2018 PACE forecast, a 50-percent CONE planning year 2018-2019, and a 100-percent CONE planning year 2018-2019, correct?
A Yes.
Q And the 2018 PACE forecast that is referenced here was a PACE forecast of capacity prices specifically from June of 2018 or thereabouts, correct?
A A little bit earlier than June, but somewhere that spring.
Q O.K. So we're going to be talking today or maybe tomorrow about a PACE September 2018 forecast and about a PACE very recent November 2018 forecast, and so I'm just looking for a way to refer to the 2018, what's listed here as the 2018 in a way that won't be confusing on the

record; so I can call it the June 2018, the May 2018, what would be most accurate in your view?
A I am fine with calling it the June 2018 PACE forecast.
Q O.K. That's my only reason is to distinguish it from the other forecasts that we're going to be discussing.
The June 2018 PACE forecast states capacity prices for 2018-2019 of $3.65, and 2019 and 2020 of $1.50. Do you see that?
A Yes.
Q Do you know what units those are in?
A I think so, but I want to doublecheck --
(Multiple speakers.)
Q Please do. I think so, too, but I'm checking through you.
A I believe it's a dollar per kilowatt year.
Q Thank you. And that's true of all the units for all these forecasts, correct, these three capacity price forecasts?
A Yes.
Q The 2018-2019 and 2019-2020 refer to MISO planning year; is that correct?
A Yes.
Q And those run from when to when, in your understanding?
A I believe it's from June 1 of the first cited year to May 31 of the second cited year.

Q Thank you. So in the PACE forecast, that 2018-2019 number of $3.65 per kilowatt year is an actual from the MISO auction for that planning year, correct, and not a forecast?
A I do not believe that's correct.
Q I'm looking at page 2 -- I'm not trying to pull a surprise. I took that information from page 2 of this exhibit Footnote 2 where it says capacity pricing based on MISO auction for PY 2018, 2019, and 2018 PACE forecast thereafter.
A O.K. I see that. So I believe that's true.
Q And then the $1.50 I'm taking from that is a forecast number from this June 2018 PACE forecast, correct?
A That is my understanding.
Q The 50-percent CONE for planning year 2018-2019 -- just for context in the record, CONE refers to cost of new entry; is that correct?
A Yes.
Q And that's a MISO published number that more or less corresponds to the cost associated with a combustion, a hypothetical combustion turbine gas plant; would you agree?
A Yes, that is my understanding.
Q And so -- and then those numbers are stated -- and the significance of the planning year 2018-2019 is that

that's MISO's -- it's 50 percent of MISO's CONE value that they published for planning year 2018-19, correct?
A I believe that is correct.
Q And then 100-percent CONE, same thing, just at 100 percent instead of 50 percent, right?
A Correct.
Q Just to chalkboard some numbers, and subject to check, the 50-percent CONE value at $45.35 is about 12 times the 50-percent CONE number; would you agree?
A Could you repeat that, please?
Q Sure. So the second scenario, the 50-percent CONE planning year 2018-19, that capacity price scenario is about a dozen times the 2018 PACE forecast number, correct?
A For which year?
Q For 2018-19.
A Subject to check, I assume your math is correct.
Q So in other words, that scenario is roughly 12 times the actual MISO PRA number that was available and used at that time; would you agree?
A Subject to check, yes.
Q And likewise, the 100-percent CONE scenario for that planning year of $90.70 is roughly 24 or 25 times, subject to check, the actual number of $3.65; would you agree?

A Subject to check, yes.
Q And likewise, the 50-percent CONE value for planning year 2019-2020 is roughly 30 times the PACE forecast for 2019-20; would you agree?
A Yes.
Q And subject to check, roughly 60 times -- the 100-percent CONE number for roughly 60 times the PACE forecast for 2019-20; would you agree?
A Yes.
Q Turning to page 2 of the exhibit, page 2 of the exhibit presents the results at these three capacity sensitivity scenarios; would you agree?
A Yes.
Q And as I interpret the footnotes, and as I believe you state in your direct testimony, the way these results are presented, it means that for the scenario involving the PACE, the June 2018 PACE forecast, there is an economic, an NPV economic benefit of retiring River Rouge at the end of 2018 of $15 million over continued operation to the currently scheduled 2020 retirement date; would you agree?
A Yes.
Q So all I'm trying to establish -- so there's a lot of things to talk about, right. All I want to establish here is that a positive number as presented in these

results is, first of all, in millions, and second of all, a positive number means a benefit of early retirement whereas a negative number means a detriment in terms of NPV economic results of early retirement; is that a fair interpretation?

A Yes.

Q Now, we know based upon the footnotes that, at least as to planning year 2018-2019, the PACE forecast is more accurate than the 50- or 100-percent CONE forecast, would you agree, because it's based on actuals?

A I'm not sure I would.

Q O.K.

A Because when we ran this analysis, it was after the auction, so the auction was not available to us at that point in time because it's run just once a year, and so when we ran this, if we were to try to replace the capacity that we had committed, we would have to do it outside the auction because this was after the auction. The auction was no longer an option for us.

Q Sure. So just to elaborate on that answer and to discuss that answer a little bit, what I take you as saying is that the -- if a replacement of capacity was to be made after the auction, you're postulating that it could be at a price that was higher than the auction price because the auction had already occurred?

A Yes.
Q For purposes of the -- for purposes of the NPV -- what is CONE in your understanding, not what is it -- we already talked about what is it made up of, or how is it determined, but what is it used for by MISO?
A So I'm not a MISO expert, but my general understanding is that in the context of the MISO planning reserve auction, CONE is the price at which capacity would have to be purchased if there was not enough resources in the auction to cover the need. So if there's not enough capacity, price rises to CONE. Whether or not -- and then you could pay the CONE price and meet your requirement whether or not there's actually any capacity there.
Q So if the auction's held and there's insufficient resources available, the price goes to CONE?
A That's my general understanding.
Q And we know that at the auction, the auction was held and sufficient resources were available and so the price did not go to CONE for the planning year 2018-2019?
A At that point in time when the auction was held, correct.
Q We know that there's -- so in other words, we know that it's -- there is not a scenario in which capacity goes to CONE, to 100 percent of CONE in 2018-2019?
A For the purposes of the auction, it did not go to CONE.

If you purchase something outside of the auction, I don't know what the price would be.

Q Sure. There's not any scenario where MISO is setting prices at 100 percent of CONE during planning year '18-19 based on known data at this time, correct?

A The auction happened and the price did not clear at CONE.

MR. BZDOK: Can I have just one moment, your Honor?

JUDGE WALLACE: Yes.

(Brief pause.)

Q (By Mr. Bzdok): When is the auction held?

A I don't remember exactly, but I think it's either April or March most years.

Q In time for the new planning year that begins on June 1?

A Correct.

Q So that's six and a half months from now; would you agree? So I'm talking about the start of planning year 2019-2020 is six and a half months from now, give or take?

A Correct.

Q Is there any realistic reason to expect that the MISO price of capacity is going to go to 100 percent of CONE in six and a half months?

A It's uncertain. I don't know what will happen in the next six months. If resources go away unexpectedly, it

certainly could go to CONE.
Q One of your documents is Exhibit, proposed Exhibit MEC-125, if could you flip to that, which is Discovery Response MECNRDCSCDE-11.11ei, a response by you and by Mr. Arnold, correct?
A Yes.
Q And here the question asks you to confirm that in the 2018-2019 MISO PRA -- you understand PRA to be planning resource auction, that's the auction we're talking about, right?
A Correct.
Q Zone 7 offers submitted exceeded the Zone 7 LCR by 1,408 UCAP megawatts. Do you see that?
A The question asked us to confirm that, and we did confirm that.
Q And what is -- LCR is the local clearing requirement, correct?
A Correct.
Q And what does it mean to say that the Zone 7 offers exceeded the Zone 7 LCR by 1,408 UCAP megawatts, what does that mean in general terms?
A O.K. I'm not an expert in MISO, but generally I take that to mean that offers from various providers added up to 1,408 megawatts more than the LCR.
Q So for -- so for six and a half months from now, for MISO

to set capacity prices at 100 percent of CONE, there would have to be a delta of at least 1,408 megawatts less offered in the next auction relative to the LCR than in this one; would you agree? There would have to be a swing in that number of at least 1,408 UCAP megawatts?
A I do not agree.
Q O.K. Explain.
A The LCR may change.
Q So let me rephrase my question, then, because I think I -- my question concerned the amount by which the offers exceeded the LCR, and so I agree with you, if the L -- this is -- what's being confirmed here is a fact about two things, right, one is a fact about a relationship, that the offers exceeded the LCR by a certain amount, correct?
A In the 2018 auction, yes.
Q Yes. And the -- so when I was asking about a swing of at least 1,408 UCAP megawatts, I was asking you about there would have to be at least that much change in the amount by which in the next auction offers compared to the LCR. Maybe I can --
A I struggle with the way you worded that, so I don't know how to answer it.
Q O.K. So let me -- I didn't word it very well. The combination of the offers submitted and the LCR for

'19-20 would have to swing by at least 1,408 UCAP megawatts in order for Zone 7 capacity prices to go to CONE for '19-20?

A I'll restate how I think what you said. LCR could go up or offers could go down, either of those changes would have to happen to get to the point where there was zero excess, and that would create a CONE result out of the next auction. You'd have to have movements in one or the other such that there is no excess.

Q Or a combination of the two?

A Or a combination of the two.

Q So understanding that -- so acknowledging that we're having a general discussion and that nobody knows for sure whatever happens in the future, is there some specific reason, some specific fact or circumstance that you're aware of why we would expect that a shift of that magnitude would happen between now and June of 2019?

A So the prior conversation with Witness Arnold talked about changes in capacity import limit and the local reliability requirement that we already know some changes have happened, and then if you add in possible changes of plants that could be offered, or the combination of all three of those, it could certainly happen that we don't meet LCR in the 2019 auction.

Q So again, granting that it's fair that things could

happen, I guess what I'm asking is, is there any specific fact or evidence or circumstances that a swing of this magnitude is likely to happen?

MR. CHRISTINIDIS: Your Honor, let me place an objection. I think this question has been asked and answered, and Witness Dimitry has pointed to a prior discussion with Witness Arnold that talked about the same set of circumstances and how those had changed.

MR. BZDOK: I'll rephrase the question.

JUDGE WALLACE: All right.

Q (By Mr. Bzdok): So in answer to that question, what I'm taking you to be saying is you're not aware of anything besides what may have been discussed by Witness Arnold, any fact, specific facts or circumstances beyond what he discussed?

A So I'm aware there already have been changes in LRR and CIL that are fairly significant and, therefore, it wouldn't take much in terms of changes in offers or changes in plant availability to get to the point where there's -- where we don't meet LCR.

Q Has MISO ever set capacity prices to 100-percent CONE before based on a failure to meet LCR or some other resource adequacy requirement?

A I'm not aware, but that -- it certainly could happen. The world is different today than it was in the past.

Q It never has happened, right?
A I'm not aware, I haven't studied the history.
Q Do you have a copy of Avi Allison's exhibits with you by any chance on the stand?
A I believe I have some, I don't know if I have all of them.
Q I'm looking for Exhibit MEC-90, which is a Discovery Response MECNRDCSCDE-5.21, and I'm happy to give you a copy if you don't have it.
A Can you state it again?
Q So it's Exhibit MEC-90, and the source is a Discovery Response 5.21 from you to us.
A I don't believe I have that.
(Document shown to Mr. Christinidis and provided to the witness.)
MR. BZDOK: Do you have it, Judge? Do you have a copy?
JUDGE WALLACE: I don't have it with me.
(Document Provided to Judge Wallace.)
JUDGE WALLACE: Thank you.
Q (By Mr. Bzdok): Ms. Dimitry, this is a discovery response by you, correct?
A Yes.
Q Give me just a second to pull it up. And I think it's going to pop up on the screen in a second. But this is a

question about the capacity price forecast used in the Company's 2019 PSCR filing, correct?
A That's part of what's on this page, yes.
Q And the -- and there's a response that the forecast used in the 2019 PSCR filing is slightly different than what's referred to here as the 2018 column in -- it's slightly different than the June 2018 PACE forecast for short, right?
A Yes.
Q And the second page of the attachment provides that capacity price forecast that was used in the 2019 PSCR plan and is now projected on the screen, correct?
A I'm having trouble remembering whether this is the September or the June PACE forecast. The column says June 2018, but the attachment names the September, so I'm --
Q Sure. So I'm looking at the answer, which has a table with three columns in it, and there's a planning year and a first column that says capacity (dollars per kilowatt year), PSCR, it has the case number, September 2018, and then there's a second column capacity (dollars per kilowatt year) 2.4d, this case number, June 2018; do you see that?
A Yes.
Q Does that refresh your memory as to --

A I believe that's what it is, I'm just confused by the fact that there's a September reference in the attachment. But the table is what I believe you just said.

Q And even the doc name in the attachment at the bottom is a, in the Excel name it has, it says PACE capacity forecast September 2018; do you see that?

A That's the piece that's confusing me between June and September.

Q O.K. So explain that to me -- explain that to me again, because when you said that, I thought you were referring to something you were seeing on page 2 when you referred to the attachment.

A I'm sorry. The table in the text of the answer is saying it's a June 2018, the attachment name listed below says September 2018, and I don't know if it was labeled wrong or whether it was meant to be the June 2018. I just don't know whether we made a mistake.

Q O.K. So I'm looking -- so now I'm looking at the text below the table. The second sentence of that little paragraph below the table in the answer says, "For all the years of the most recent (September 2018) Capacity price forecast (from which the years 2018-2023 of the above U-20221 PSCR forecast were taken), please see the attachment."

A O.K. So thank you for pointing that out. I believe the table in the text is from the June 2018, and that the attachment is the September 2018 PACE forecast.
Q Got it. O.K. Looking at this -- so I think where we've landed is the, at least we're confident that the attachment, the page 2 of this exhibit, proposed MEC-90, is the September 2018 PACE capacity forecast?
A That's what I believe it is, yes.
Q And just to orient us, if we go all the way to the right and then we count one, two, three, four columns back, there's a capacity price final in dollars per kilowatt year; do you see that?
A Yes.
Q And there's, for 2018-19, there's a 3.7; do you see that?
A Yes.
Q And that's that actual from the PRA auction '18-19; would you agree?
A Yes.
Q And then for year 2019-20, there's a forecast of $1.46 per kilowatt year, right?
A Yes.
Q And then it stays below $1.50 for the next couple years and then eventually it gets, by 2025-26 -- sorry -- 2026-27, it gets up above -- it gets up to -- it shoots up from about $1.50 to about $13.00; do you see that?

A Yes.
Q O.K. So in your rebuttal testimony on page 4, which I'm also projecting the bottom of that on the screen, you're talking about capacity price forecasts and how they relate to this River Rouge NPV analysis, correct?
A Give me a moment to get there, please.
Q Please take your time.
A I'm there. Could you re-ask the question?
Q All I was asking at this point was to get to there.
A I'm there.
Q At the bottom of page 4 of your rebuttal where you're talking about this subject matter, you have a Figure 1 capacity price forecast and you have some graphs here, correct?
A Correct.
Q And the, what's labeled as high, the black line at the top, is the 100-percent CONE forecast; is that correct?
A Yes.
Q And the mid is the 50-percent CONE; is that correct?
A Yes.
Q And the red line at the bottom is that June 2018 PACE forecast, correct?
A Yes.
Q The September 2018 capacity price forecast is not in this figure at all, is it?

A Correct.
Q Why not?
A Because it had been updated and we wanted to show the most, the latest forecast we had gotten from PACE.
Q Had you included the September 2018 forecast, it would have been at or even slightly below the red line that's marked as low at the bottom, right, based on the numbers we just reviewed?
A Approximately, but the November forecast included changes based on updates from MISO, so that's why we used the November forecast.
Q So let's talk about the November forecast. The November forecast is referenced in proposed Exhibit MEC-122; is that correct?
A It doesn't say November on there, so I want to check something. I believe that is what it was referring to, the November PACE forecast.
JUDGE WALLACE: Where it says most recent version would be November?
THE WITNESS: Yes.
Q (By Mr. Bzdok): And that was a capacity price forecast that was provided to us in supplemental discovery reflected in proposed Exhibit MEC-122, correct?
A Yes. The supplement was to provide the updated November forecast.

Q O.K. And this was provided to us on the early evening of November 27, 2018; is that correct?
A Subject to check, yes.
Q Would you like to see the cover letter?
A I don't doubt, I just don't remember what day it was off the top of my head.
Q O.K. And the Company filed, then, its rebuttal testimony on November 28, 2018, the next day, right?
A We did file rebuttal on the 28th, I do remember that.
Q And in your rebuttal testimony, you discuss this November 2018 forecast that was provided to us the evening before, correct?
A Subject to check, yes.
Q And including, but not limited to, its use in this figure for capacity price forecasts as represented as the green line, correct?
A Yes.
Q So we never got a workpaper for this figure, so I have a couple questions about it that are sort of basic. One is are these years 2018, '19, '20, '21, '22, '23, are those calendar years or are those the MISO planning years?
A I believe they are the planning years represented by the -- what would be shown as 2018 is really the 2018-19 planning year, 2019 would be 2019-20 planning year, et cetera.

Q O.K.

JUDGE WALLACE: Mr. Bzdok, are we coming to a stopping point here fairly soon?

MR. BZDOK: I will stop whenever you would like. I'm not quite to the confidential session, but I'm also happy to just stop and pick up tomorrow.

JUDGE WALLACE: O.K. How about we stop now and we'll pick it up tomorrow and then we'll go into the -- is that O.K.? You've got a couple questions about this graph, so why don't you finish those up.

Q (By Mr. Bzdok): So my other question about the graph, due to the absence of a workpaper, was when was it prepared?

A As I was working on the rebuttal somewhere in the week or so before I submitted it.

Q Did you prepare it or did somebody else?

A The chart was prepared by members of my team at my direction when they told me they had gotten a new forecast.

Q When did they tell you that?

A I don't remember exactly. It was as I was preparing my rebuttal.

Q And to the best of your knowledge, what timeframe was that?

A A week to -- within a week or so of before I filed.

MR. BZDOK: Your Honor, I think that's a good stopping point to pick up from tomorrow, if that's --

JUDGE WALLACE: All right.

MR. BZDOK: And I thank you for your time today.

THE WITNESS: Thank you.

(The witness was excused, subject to re-call.)

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JUDGE WALLACE: All right. Very good.

MR. BZDOK: Your Honor, I was just reminded that perhaps it might be useful to admit the exhibits that I have identified and discussed specifically so far.

JUDGE WALLACE: O.K.

MR. BZDOK: If that would be O.K.?

JUDGE WALLACE: Sure.

MR. BZDOK: So that is specifically MEC-122 and MEC-125.

JUDGE WALLACE: Is there any objection to the admission of MEC-122 or MEC-125? (No response.)

Hearing none, MEC Exhibit 122 and MEC Exhibit 125 are admitted.

MR. BZDOK: Thank you very much.

JUDGE WALLACE: Is there anything else we

need to discuss? (No response.) O.K. So tomorrow we're going to start with motions to strike, if that's O.K., first thing on Mr. Paul's testimony, or do we want to wait until we conclude with this witness and then hear those motions?

MR. BZDOK: I'm easy.

MR. CHRISTINIDIS: Whatever your pleasure, your Honor.

JUDGE WALLACE: Nobody cares. We'll figure it out tomorrow. Thank you all very much. And we are off the record, and I will see you tomorrow at 9:00.

(At 5:25 p.m., the hearing was adjourned to Thursday, December 13, 2018.)

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C E R T I F I C A T E

We, Marie T. Schroeder and Lori Anne Penn, do hereby certify that we reported in stenotype the proceedings had in the within-entitled matter, that being Case No. U-20162, before Sally L. Wallace, Administrative Law Judge with MAHS, at the Michigan Public Service Commission, Lansing, Michigan, on Wednesday, December 12, 2018; and do further certify that the foregoing transcript, consisting of Volume 3, is a true and correct transcript of our stenotype notes.

Marie T Schroeder

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